EL PASO ELECTRIC COMPANY
SERVICE LIFE ANALYSIS FOR TRANSPORTATION
AUGUST 2005-SEPTEMBER 2016

Year of Sale	Month Retired	Property Type	Original Cost	Accumulated Reserve	Net Book Value	Month In-Service	Actual Years In Service	Average Years In Service
2012	Jun-12	Light Duty Vehicles	24,650	(24,650)	-	Feb-03	9.34	
2007	Oct-07	Light Duty Vehicles	19,649	(10,188)	9,461	Feb-04	3.67	
2007	Oct-07	Light Duty Vehicles	32,986	(17,671)	15,315	Feb-04	3.67	
2007	Oct-07	Light Duty Vehicles	21,200	(11,357)	9,843	Feb-04	3.67	
2009	Aug-09	Light Duty Vehicles	26,249	(20,937)	5,312	Feb-04	5.50	
2010	Sep-10	Light Duty Vehicles	30,346	(28,993)	1,353	Feb-04	6.59	
2010	Sep-10	Light Duty Vehicles	30,647	(28,488)	2,160	Feb-04	6.59	
2010	Sep-10	Light Duty Vehicles	28,155	(26,198)	1,957	Feb-04	6.59	
2011	Sep-11	Light Duty Vehicles	35,241	(35,241)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	79,657	(79,657)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	50,114	(50,114)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	27,125	(27,125)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	36,481	(36,481)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	26,009	(26,009)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	29,728	(29,728)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	28,418	(28,418)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	25,105	(25,105)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	26,255	(26,255)	-	Feb-04	7.59	
2011	Sep-11	Light Duty Vehicles	25,046	(25,046)	-	Feb-04	7.59	
2012	Jun-12	Light Duty Vehicles	32,446	(32,446)	-	Feb-04	8.34	
2012	Jun-12	Light Duty Vehicles	26,455	(26,455)	-	Feb-04	8.34	
2012	Jun-12	Light Duty Vehicles	34,445	(34,445)	-	Feb-04	8.34	
2012	Jun-12	Light Duty Vehicles	29,187	(29,187)	-	Feb-04	8.34	
2012	Jun-12	Light Duty Vehicles	28,155	(28,155)	-	Feb-04	8.34	
2012	Jun-12	Light Duty Vehicles	28,155	(28,155)	-	Feb-04	8.34	
2012	Jun-12	Light Duty Vehicles	28,155	(28,155)	-	Feb-04	8.34	
2012	Aug-12	Light Duty Vehicles	28,765	(28,765)	-	Feb-04	8.50	
2012	Aug-12	Light Duty Vehicles	32,121	(32,121)	-	Feb-04	8.50	
2012	Aug-12	Light Duty Vehicles	28,775	(28,775)	-	Feb-04	8.50	
2012	Aug-12	Light Duty Vehicles	30,346	(30,346)	-	Feb-04	8.50	
2012	Aug-12	Light Duty Vehicles	28,765	(28,765)	-	Feb-04	8.50	
2012	Aug-12	Light Duty Vehicles	30,346	(30,346)	-	Feb-04	8.50	
2012	Aug-12	Light Duty Vehicles	30,346	(30,346)	-	Feb-04	8.50	
2012	Aug-12	Light Duty Vehicles	28,155	(28,155)	-	Feb-04	8.50	
2014	Jul-14	Light Duty Vehicles	45,076	(45,076)	-	Feb-04	10.42	
2007	Oct-07	Light Duty Vehicles	21,715	(8,531)	13,184	Dec-04	2.83	
2007	Oct-07	Light Duty Vehicles	21,385	(8,401)	12,984	Dec-04	2.83	
2007	Oct-07	Light Duty Vehicles	21,385	(8,243)	13,142	Dec-04	2.83	
2007	Oct-07	Light Duty Vehicles	21,385	(8,401)	12,984	Dec-04	2.83	
2007	Oct-07	Light Duty Vehicles	21,385	(8,243)	13,142	Dec-04	2.83	
2009	Aug-09	Light Duty Vehicles	15,235	(3,446)	11,789	Dec-05	3.67	
2009	Aug-09	Light Duty Vehicles	15,727	(3,557)	12,170	Dec-05	3.67	
2009	Aug-09	Light Duty Vehicles	19,429	(4,395)	15,034	Dec-05	3.67	
2009	Aug-09	Light Duty Vehicles	16,775	(3,794)	12,981	Dec-05	3.67	
2010	Sep-10	Light Duty Vehicles	35,678	(13,592)	22,087	Dec-05	4.75	
2010	Sep-10	Light Duty Vehicles	16,034	(6,108)	9,926	Dec-05	4.75	
2011	Sep-11	Light Duty Vehicles	35,943	(18,827)	17,116	Dec-05	5.75	
2014	Jun-14	Light Duty Vehicles	41,615	(38,147)	3,468	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	28,016	(25,681)	2,335	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	36,828	(33,759)	3,069	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	28,503	(26,128)	2,375	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	41,105	(41,105)	-	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	53,785	(49,303)	4,482	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	32,881	(30,141)	2,740	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	38,261	(35,072)	3,188	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	45,206	(41,439)	3,767	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	17,723	(17,723)	-	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	31,575	(28,944)	2,631	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	20,319	(18,625)	1,693	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	18,197	(16,680)	1,516	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	24,099	(22,091)	2,008	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	23,451	(21,496)	1,954	Dec-05	8.50	
2014	Jun-14	Light Duty Vehicles	45,012	(41,261)	3,751	Dec-05	8.50	
2014	Jul-14	Light Duty Vehicles	58,950	(54,739)	4,211	Dec-05	8.59	
2012	Aug-12	Light Duty Vehicles	37,633	(29,120)	8,512	Feb-07	5.50	

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2014	Jun-14	Light Duty Vehicles	38,635	(38,635)	-	Feb-07	7.33	
2014	Jul-14	Light Duty Vehicles	41,946	(36,568)	5,378	Feb-07	7.42	
2014	Jun-14	Light Duty Vehicles	27,365	(14,986)	12,379	Jul-10	3.92	
2014	Jul-14	Light Duty Vehicles	45,076	(45,076)	-	Feb-04	9.7	
2014	Jul-14	Light Duty Vehicles	41,946	(36,568)	5,378	Feb-07	7.4	
2014	Jul-14	Light Duty Vehicles	58,950	(54,739)	4,211	Dec-05	8.6	
2015	Aug-15	Light Duty Vehicles	54,218	(54,218)	-	Feb-04	10.8	
2015	Aug-15	Light Duty Vehicles	43,936	(43,936)	-	Feb-04	10.8	
2015	Aug-15	Light Duty Vehicles	62,988	(62,988)	-	Feb-04	10.8	
2015	Aug-15	Light Duty Vehicles	14,722	(14,722)	-	May-07	8.3	
2015	Aug-15	Light Duty Vehicles	19,508	(19,508)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	19,139	(19,139)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	20,333	(20,333)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	18,419	(18,419)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	23,451	(23,451)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	38,264	(38,264)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	37,673	(37,673)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	37,107	(37,107)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	23,451	(23,451)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	34,519	(34,519)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	44,538	(44,538)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	24,353	(24,353)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	17,141	(17,141)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	17,141	(17,141)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	17,373	(17,373)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	17,141	(17,141)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	17,141	(17,141)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	17,141	(17,141)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	17,141	(17,141)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	15,173	(15,173)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	15,173	(15,173)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	17,781	(17,781)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	21,314	(21,314)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	16,701	(16,701)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	38,338	(38,338)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	15,707	(15,707)	-	May-07	8.3	
2015	Aug-15	Light Duty Vehicles	28,808	(28,808)	-	May-07	8 3	
2015	Aug-15	Light Duty Vehicles	19,658	(19,658)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	41,668	(41,668)	-	Dec-05	9 7	
2015	Aug-15	Light Duty Vehicles	19,511	(19,511)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	19,511	(19,511)	-	Dec-05	9.7	
2015	Aug-15	Light Duty Vehicles	16,692	(16,692)	-	Sep-10	4.9	
2015	Dec-15	Light Duty Vehicles	23,036	(23,036)	-	Dec-05	10.0	
2015	Dec-15	Light Duty Vehicles	38,341	(38,341)	-	Dec-05	10.0	
2016	Nov-16	Light Duty Vehicles	29,715	(29,715)	-	Feb-04	12.1	
2016	Nov-16	Light Duty Vehicles	23,408	(23,408)	-	Jun-08	8.4	
2016	Nov-16	Light Duty Vehicles	17,114	(17,114)	-	Jun-08	8.4	
2016	Nov-16	Light Duty Vehicles	26,255	(26,255)	-	Jun-08	8.4	
2016	Nov-16	Light Duty Vehicles	20,060	(20,060)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	17,208	(17,208)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	17,026	(17,026)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	17,026	(17,026)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	23,451	(23,451)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	17,141	(17,141)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	20,469	(20,469)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	17,781	(17,781)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	20,236	(20,236)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	20,236	(20,236)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	37,353	(37,353)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	37,353	(37,353)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	37,353	(37,353)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	20,856	(20,856)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	26,775	(26,775)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	17,581	(17,581)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	17,581	(17,581)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	22,331	(22,331)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	22,331	(22,331)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	17,157	(17,157)	-	Dec-05	10.9	

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Year of Sale	Month Retired	Property Type	Original Cost	Accumulated Reserve	Net Book Value	Month In-Service	Actual Years In Service	Average Years In Service
2016	Nov-16	Light Duty Vehicles	23,631	(23,631)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	23,631	(23,631)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	22,894	(22,894)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	18,604	(18,604)	-	Dec-05	10.9	
2016	Nov-16	Light Duty Vehicles	16,123	(16,123)	-	Jun-08	8.4	
2016	Nov-16	Light Duty Vehicles	23,758	(23,758)	-	May-07	9.5	
2016	Nov-16	Light Duty Vehicles	21,467	(16,903)	4,564	Jul-10	6.3	
		Light Duty Vehicles Total	6,443,650	(6,104,952)	338,698			
		Grand Total	16,046,945	(15,501,450)	545,495			

Average years in service: 8.98

DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

GEORGE NOVELA

FOR

EL PASO ELECTRIC COMPANY

FEBRUARY 2017

EXECUTIVE SUMMARY

George Novela is the Manager of the Economic Research Department at El Paso Electric Company ("EPE" or "Company"). In his testimony, he discusses the energy and demand forecast and EPE's load studies. He also describes and supports EPE's weather normalization adjustment. The energy and demand forecast model is used to generate long-term sales and demand forecasts which are used by EPE's Resource Planning and Transmission and Distribution Departments to plan the generation, transmission, distribution, and firm purchased power resources needed to meet the projected peak load in a reliable and cost-effective manner over time. The energy and demand forecast methodology is described, along with the historical data used to estimate the model. The 2016 long-term energy and demand forecast is shown in Exhibit GN-2.

Load studies are used in support of a number of functions including allocation of sales among rate classes and jurisdictions, rate studies, class contribution to peak, load factor analysis, cost allocation, etc. Mr. Novela's testimony describes the load research process used to collect and summarize load study data. His testimony further addresses how sales and demand are allocated by class, voltage, and jurisdiction. The testimony also discusses the use of loss factors to reconcile the native energy used by retail and wholesale customers to the amount of electricity delivered to the system by EPE generation units and purchased power. In addition, it provides the history of EPE's system peak demand. Finally, it examines the weather patterns in both Las Cruces, New Mexico and El Paso, Texas and explains the necessity for the Company's proposed weather normalization adjustment to Test Year sales to levels that are reasonably anticipated to occur from year to year. The total weather adjustment for Texas retail customers is a decrease of 17,793,008 kWh (-0.29 percent) from total Texas retail Test Year sales of 6,175,132,723 kWh.

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION & QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, AND BUSINESS ADDRESS.

A. My name is George Novela. My business address is 100 North Stanton Street, El Paso, Texas 79901-1341.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "Company").

Q. WHAT IS YOUR CURRENT POSITION WITH EPE?

A. I am Manager of the Economic Research Department.

Q. HOW LONG HAVE YOU BEEN EMPLOYED AT EPE?

A. I have been employed by EPE since November of 2008.

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES AS MANAGER OF ECONOMIC RESEARCH?

A. I am responsible for the economic forecasting and load research functions. I manage and direct the activities of the Economic Research Department, including the preparation of long-term customer, energy, and load forecasts; analysis of load research data; and the preparation of load research studies and reports.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Texas at El Paso with a Bachelor of Business Administration in Economics in 2006, a Master of Science in Economics in 2008, and a Master of Business Administration in Finance in 2012. I received a Graduate

Certificate in Public Utility Regulation & Economics from New Mexico State University in 2014.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. Prior to working at EPE, I worked as the Research Coordinator for the City of El Paso's Department of Economic Development from 2007 to 2008. My duties included calculating incentive packages for new and expanding businesses, producing impact studies, and coordinating recruitment efforts with various public and private stakeholders.

In 2008, I began working for EPE as a Load Research Specialist, where I specialized in analyzing EPE's large customers. I was promoted to Senior Economist in 2011, in which my responsibilities included the development of the long-term energy, demand, and customer forecasts utilized for planning purposes. In 2014, I worked briefly for EPE's Energy Efficiency Department as a Program Coordinator before moving into my current role as Manager of Economic Research. As a Program Coordinator, I oversaw energy efficiency initiatives for residential customers in both Texas and New Mexico.

In addition, I taught undergraduate courses in Macroeconomics and Microeconomics at El Paso Community College from 2012 to 2013.

Q. PRIOR TO THIS MATTER, HAVE YOU EVER PROVIDED TESTIMONY IN A REGULATORY PROCEEDING?

A. Yes, I have filed testimony with the New Mexico Public Regulation Commission and the Public Utility Commission of Texas ("PUCT" or "Commission").

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide EPE's historical and forecasted sales and demand data in support of EPE's rate request, to describe the load research function and its role in gathering the energy and demand data necessary for assigning costs to rate classes and the development of tariffs, as well as to describe and support EPE's proposed weather normalization adjustments.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I will provide historical and forecasted sales and demand data in support of EPE's rate request. In addition, I sponsor and co-sponsor related schedules in EPE's rate filing package. In my testimony, I summarize the structure, history, and outlook of the economy for EPE's service area. I describe EPE's forecasting methodology and the assumptions that support the demand and energy forecasts presented in my testimony. I also sponsor the Company's current demand and energy forecast with monthly energy requirements for EPE's proposed Rate Year: July 1, 2017, to June 30, 2018. EPE's most recent long-term load forecast is dated April 7, 2016.

Second, I provide a description of the load research function and its role in gathering energy and demand data necessary for assigning costs to rate classes and the development of tariffs. I provide information about the types of studies conducted by the load research program and the different rate classes for which these studies are performed.

Third, my testimony describes and supports EPE's proposed weather normalization adjustments. My testimony provides a description of the methodology I used to calculate the impact of Test Year temperatures on EPE's sales and revenues. My testimony also explains how the econometric models of energy consumption by rate class were developed, and how the results of those models were used to quantify the monthly weather normalization adjustments for each class of service.

Q. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes, I sponsor the eight exhibits that are identified in the list of exhibits found in the table of contents of this testimony.

Q. WHAT SCHEDULES DO YOU SPONSOR?

A. The schedules I am sponsoring or co-sponsoring are listed with descriptions in Exhibit GN-1.

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING OR CO-SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. EPE ENERGY & DEMAND FORECAST

A. EPE Customers and Service Area Economy

Q. PLEASE PROVIDE A DESCRIPTION OF EPE'S RETAIL SERVICE AREAS.

A. EPE's retail customers are located in far west Texas and southern New Mexico. The Texas retail jurisdiction includes El Paso County and portions of Hudspeth and Culberson counties. The Texas retail jurisdiction accounts for approximately 79 percent of EPE's retail energy sales. The New Mexico retail jurisdiction includes Doña Ana County and portions of Otero, Luna, and Sierra counties and accounts for the remaining 21 percent of retail sales. El Paso and Doña Ana counties had estimated 2015 populations of 835,593 and 214,295, respectively.

Q. DOES EPE HAVE ANY FIRM WHOLESALE CUSTOMERS?

A. Yes. EPE provides firm wholesale service to the Rio Grande Electric Cooperative ("RGEC") at two delivery points that are adjacent to EPE's service area: 1) the Dell City delivery point in Hudspeth County; and 2) the Van Horn delivery point in Culberson County. RGEC is a full requirements customer and is, therefore, part of EPE's native system load. RGEC's 2016 peak load was approximately 15 Megawatts ("MW").

Q: PLEASE DESCRIBE THE ECONOMIC COMPOSITION OF EPE'S SERVICE AREA.

A. The majority of EPE's load is distributed within the local Metropolitan Statistical Areas ("MSA") of El Paso, Texas (composed of El Paso and Hudspeth counties), and Las Cruces, New Mexico (composed of Doña Ana County). Over the last year (the 12 months ending September 2016), the El Paso area has experienced employment growth in the construction, transportation, warehousing, government, financial, business services, leisure/hospitality, education, and health sectors. It has experienced declines in both the manufacturing and information sectors.

The two largest industry components and drivers of the El Paso MSA economy have been transportation/warehousing and government. EPE's service territory has a large transportation and warehousing industry attributable to its location along the United States-Mexico border, as well as its proximity to manufacturing operations in a free trade zone, i.e., maquiladoras in Mexico. The transportation and warehousing sector accounts for about 21 percent of total non-farm employment in El Paso. Other local industries such as manufacturing are also affected by, and in many cases dependent on, the existence and the success of the maquiladoras in Mexico.

The government sector accounts for about 23 percent of total non-farm employment in El Paso. In addition to federal, state, and local government, total government employment includes the U.S. Army at Fort Bliss, Texas. Fort Bliss has grown from a full-time active duty troop size of 10,000 in 2005 to approximately 28,500 in 2015. The increase was caused by the 2005 Base Realignment and Closure ("BRAC") process that called for the local military presence to grow steadily through 2013.

The Las Cruces MSA economy is characterized by a large government sector dominated by White Sands Missile Range ("WSMR") and New Mexico State University. WSMR is geographically the largest military installation in the United States with approximately 3,200 square miles. WSMR and the 600,000-acre McGregor Range Complex at Fort Bliss are contiguous areas for military testing and both are in EPE's service territory. EPE also serves Holloman Air Force Base in Otero County, which is another significant government entity in New Mexico. The government sector directly accounts for approximately 28 percent of total employment in Las Cruces. Las Cruces also has the commercial establishments necessary to serve the remaining sectors, including a substantial and growing retirement community.

Q. WHAT IS THE OUTLOOK FOR THE SERVICE AREA ECONOMY?

A. Through the year 2021, the compound annual growth rate ("CAGR") for the El Paso MSA total nonfarm employment is expected to be approximately 1 percent each year. Census data indicates that the CAGR for population in El Paso from 2010 to 2015 was 0.9 percent, lower than the state population growth rate of 1.8 percent, but slightly higher than the national average of 0.8 percent. The population for the El Paso MSA is expected to grow approximately 1.1 percent annually over the next 5 years. Total real gross metropolitan product in El Paso was about $25.1 billion in 2014, and is estimated to have been $25.9 billion at the end of 2015, with a continued CAGR hovering around 1.6 percent through the year 2021.

Q. DID YOU UTILIZE INDEPENDENT ANALYSES TO SUPPORT THE OUTLOOK FOR THE SERVICE AREA ECONOMY?

A. Yes. EPE uses a variety of sources to gauge the local economy. It is important to gather various viewpoints from different and established subject matter experts in order to get a clear understanding of the local economy. EPE obtains forecasted regional economic data for El Paso and Las Cruces from IHS Economics ("IHS"). In addition, EPE uses data from the Texas Workforce Commission, Texas A&M Real Estate Center, Texas Comptroller of Public Accounts, and the Federal Reserve Bank of Dallas to support the outlook for the service area economy.

Q. WHAT IS THE PRIMARY SOURCE OF DATA THAT EPE RELIED ON FOR INFORMATION REGARDING THE ECONOMIC OUTLOOK FOR THE COMPANY'S SERVICE AREA?

A. EPE relied primarily on the regional economic forecast for El Paso and Las Cruces produced by IHS. IHS is an internationally recognized data forecasting service. Given that its customer base includes clients in industry, banking, government, and academic institutions, EPE is confident in relying on the data provided by IHS.

In addition to the IHS data, EPE maintains direct contact with its large customers, including Fort Bliss, WSMR, and others. This helps EPE to continuously evaluate the economic outlook for the region.

Q. ARE THERE SIGNIFICANT ECONOMIC FACTORS RELATED TO MEXICO THAT AFFECT THE EL PASO ECONOMY?

A. Yes, there are. The maquiladora industry affects cities along both sides of the U.S.-Mexico border, which is supported by a 2013 study conducted by the Federal Reserve Bank of Dallas ("Bank"). This study, which is available at the Bank's website titled "The Impact of the Maquiladora Industry on U.S. Border Cities," found that a 10 percent increase in export production in Ciudad Juarez—directly across the international border from El Paso—leads to a nearly 3 percent increase in overall nonfarm employment in El Paso. The growth of the maquiladora sector in northern Mexico is tied to the level of U.S. production and relative exchange rates. Most recently, maquiladora employment in Ciudad Juarez has been increasing. Additionally, according to the Bank, manufacturing employment in Ciudad Juarez grew by more than 5.4 percent, year-over-year, ending June 2016.

Q. WHAT IS THE PROJECTED OUTLOOK WITH RESPECT TO EPE'S MILITARY CUSTOMERS?

A. The outlook for the military customers in the service territory is uncertain. Fort Bliss and WSMR may be affected by budget constraints mandated by the federal government and another future round of BRACs. The impacts of these budget constraints and a possible BRAC are unclear. The results could be a reduction in troops, or a growth in troops from absorption of troops from other bases that will no longer be in operation. Ultimately, though, a reduction or increase in troops will have a direct effect on energy and demand consumption in EPE's service territory.

Due to the 2005 BRAC, the local military presence grew steadily through 2013. Recently, Fort Bliss's troop count has remained relatively steady over the last couple of years, as has its overall load growth. Out of model adjustments were made to the incremental growth at Fort Bliss to account for a future hospital and the saturation of rooftop solar panels on post.

B. Forecast Methodology and Assumptions

Q. WHAT APPROACH DOES EPE UTILIZE TO DEVELOP ITS SALES FORECASTS?

A. EPE employs an econometric approach, which is the application of mathematics and statistical methods to the analysis of economic data and the relationship between economic variables to provide an empirical estimation of those relationships. EPE's econometric forecasting models relate customer electric usage to service area economic trends, such as population, usage per customer, employment, and income, in order to estimate future electricity sales. For example, population, personal income, and weather are typical drivers of electricity sales: more customers and increased income with which to purchase appliances will typically result in higher electricity demand.

Q WHAT METHODOLOGY DOES EPE USE TO SUPPORT THE SALES AND DEMAND FORECASTS PRESENTED IN YOUR TESTIMONY?

A. EPE relies on the regional macroeconomic forecasts prepared by IHS to support the econometric models for the energy sales forecasts for the El Paso and Las Cruces areas. EPE develops jurisdictional revenue class sales forecasts based on monthly macroeconomic data and historic and forecasted customer data for each respective jurisdiction. EPE develops individual rate class econometric forecasts if rate classes are experiencing changes not in line with their historical trend. For example, EPE develops an econometric model for its military customer in Rate 31-Military Reservation Service ("Rate 31") to adjust for the incremental adjustments it has experienced over the past several years due to BRAC, as described previously in this testimony. EPE's forecasts for energy sales are functions of variables such as population, income, employment, and other significant inputs. The econometric sales forecasts and resulting peak demand forecast were adjusted to reflect conservation, distributed generation, and load management effects not represented in the historical database.

Q. ARE ALL OF EPE'S SALES ESTIMATES BASED ON AN ECONOMETRIC MODEL?

A. No. In the few cases where adequate data was not available to support statistical analysis, EPE relied on non-econometric sales and load information. Examples of situations that require non-econometric estimates include significant expansion or reduction by an existing or new customer as well as expansion of distributed generation ("DG") customers.

As discussed previously, our military customer in Rate 31 experienced abnormally fast growth that is not reflected in its historical usage patterns. At the same time this customer has employed various energy efficiency initiatives that are reducing consumption. In this case, EPE works with this military customer and our internal customer service group to identify changing load requirements.

Finally, given that DG is relatively new, there is limited historical regional data, so it is not suitable for econometric forecasting models. Future estimates for DG customers and load are based on recent trends, sample studies, and known or reasonably predictable changes in consumption levels.

Q. HOW DOES EPE DETERMINE THE MONTHLY SYSTEM ENERGY REQUIREMENT (SALES AT THE SOURCE)?

A. EPE combines the annual retail sales, sales to RGEC, and Company use, and then calculates line losses using a loss rate derived from the system loss study conducted by, Management Applications Consulting, Inc. ("MAC") in February 2015. These system losses must be included with sales at the meter to accurately develop the total energy requirement needed to deliver electricity to EPE's customers. The annual losses are then allocated to each month based on a historical seasonal pattern. Additional line losses are incurred from off-system wheeling of EPE's power (Losses-to-Others). The system loss study is presented in the testimony of EPE witness James Schichtl. Finally, a downward adjustment is made to reflect energy efficiency and DG not represented in the historical database.

Q. HOW ARE EPE'S PEAK DEMAND FORECASTS DEVELOPED?

A. EPE uses the native system load factor relationship to estimate future annual peak demands. Load factor defines the relationship between energy and peak demand.

System Load Factor = System Energy / (Peak Demand x Hours)

For example, the annual load factor for 2015 was:

System Load Factor = 8,441,421 MWh / (1,794 MW x 8,760 hours) = 0.537

EPE applies the previous year's load factor to "at source" projected energy to calculate the estimated peak demand. These values are then adjusted for projected conservation and load management to calculate native system peak demand.

The demand from wheeling losses is also accounted for to obtain an overall system peak demand. The final adjustment made to forecasted peak demand is to subtract interruptible load. Monthly peak demand is estimated by using the historical relationship between monthly peak demands and the annual peak demand.

Q. WHAT ARE THE MAJOR UNDERLYING ASSUMPTIONS USED IN DEVELOPING EPE'S FORECASTS?

A. The major underlying assumptions for the forecasts are the projections for population, income, weather, and employment.

Q. DOES EPE RELY ON AN INDEPENDENT SOURCE IN ACCOUNTING FOR THOSE MAJOR UNDERLYING ASSUMPTIONS?

A. Yes. The population, income, and employment data series for EPE's service area are taken from the IHS regional economic forecasts for El Paso and Las Cruces that I described earlier in my testimony. IHS's forecasts provide EPE with data that is independent and free from any internal bias. IHS provides EPE with a large data set of regional variables that are routinely updated. Moreover, as previously discussed, IHS is an internationally recognized macroeconomic forecasting service with a customer base that includes clients in industry, banking, government, and academic institutions.

Q. PLEASE SUMMARIZE THE FORECASTS USED IN THIS FILING.

A. The forecast summary shows that the 10-year CAGR for native system energy and native system demand is approximately 1.4 and 1.6 percent, respectively. This is reasonable given recent customer growth trends and expected employment growth in EPE's service area over the long term. The Company's energy and demand forecast summary is provided in Exhibit GN-2.

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IV. LOAD STUDIES

A. Overview

Q. PLEASE DESCRIBE THE LOAD RESEARCH PROGRAM AT EPE.

A. EPE's Economic Research Department conducts sample and census studies of Texas and New Mexico customer energy and demand usage by rate class to estimate class coincident peak demand, maximum class demand, and non-coincident maximum demand. EPE uses this data to allocate costs to rate classes and to develop rates based on energy and demand usage. EPE also uses this data for resource planning.

Q. WHAT IS A CENSUS STUDY?

A. A census study is conducted by completely metering rate classes with an Interval Data Recorder ("IDR"). These studies are typically performed on single customer rate classes or rate classes with a low number of customers. For example, EPE's Texas Large Power Service rate class has about 100 customers, all of which have IDR meters for billing purposes. Rate classes that are based on a census study contain study data in total form, as shown in Schedule Q-5.1. There is no sampling error in developing the total class load. The data presented in Schedule Q-5.1 is based on calendar month information, so, due to differences between calendar months and billing months, the data will not exactly match billing data.

Q. FOR WHICH EXISTING RATE CLASSES IN TEXAS DOES EPE UTILIZE A CENSUS STUDY?

A. Texas rate classes that are evaluated using a census study are as follows:

- Rate 15 Electrolytic Refining Service;
- Rate 25 Large Power Service;

- Rate 26 Petroleum Refinery Service;
- Rate 30 Electric Furnace Service;
- Rate 31 Military Reservation Service;
- Rate 34 Cotton Gin Service;
- Rate 38 Large Power Interruptible Service; and
- Rate 45 Supplementary Power Service for Co-generation.

Q. WHAT IS A SAMPLE STUDY?

A. Sample studies are performed on rate classes that have a large number of customers. Sample studies are based on sampling selected members of each relevant rate class. For classes with numerous customers, it is not economically feasible to install IDR meters for every customer. For example, the Texas Residential Service rate class is examined as a sample study due to the large number of customers in the class. With approximately 278,000 Residential Texas customers in September 2016, it would not be economically feasible to install IDR meters on all customers in this class. The sample study data is shown in Schedule Q-5.2.

Q. FOR WHICH EXISTING RATE CLASSES IN TEXAS DOES EPE UTILIZE A CURRENT SAMPLE STUDY?

A. The following rate classes in Texas are sampled:

- Rate 01 Residential Service;
- Rate Rider Water Heating;
- Rate 02 Small General Service;
- Rate 11 Municipal Pumping;

- Rate 22 Irrigation;
- Rate 24 General Service; and
- Rate 41 City and County Service.

Q. FOR RATE CLASSES THAT ARE SAMPLED, WHAT ARE THE PROCEDURES EPE USES TO DEVELOP A SAMPLE DESIGN?

A. EPE uses a stratified random sample process for the sample studies. Sample designs for each load study were based on the Dalenius-Hodges stratification procedure and the Neyman allocation methodology. The Dalenius-Hodges procedure categorizes each customer into predetermined energy or demand blocks and calculates stratum boundaries based on the frequency of customers per block. It is important that each customer selected for the sample is in the appropriate strata to ensure an accurate weighted average. The Neyman allocation method is then used to calculate the optimal sample size and to allocate samples between the strata. These methods make use of available data in building efficient and cost-effective sample designs.

Q. WHAT DOES EPE DO TO COMPLETE THE DEVELOPMENT OF A SAMPLE STUDY AFTER IT IS DESIGNED?

A. After the steps described in the answer to the preceding question are complete, EPE selects customers from a random list of candidates and installs survey equipment at each customer's premise. Meter Testing personnel maintain the IDR meters and do monthly translation of the data. The Economic Research Department performs primary data analysis. The Meter Testing Department screens data to ensure the accuracy and validity of the IDR meter readings. Data judged to be within normal tolerance ranges are merged into the Load Research database.

For the analysis, a "typical customer" for each study is used for data comparison. The data for each account are collected on a continuous basis with meters read monthly. Accounts in each stratum are then averaged, producing a stratum average. Each stratum average is then multiplied by a strata weighting factor to develop the class weighted average. The strata weighting factor is the percentage of customers of the total population being sampled contained in each stratum. This weighted average represents a typical customer for each sample study. The sample studies are stratified as shown in the Schedule Q-5.2:

Q. WHAT PROCESS DOES EPE USE TO KEEP THE LOAD STUDIES CURRENT?

A. EPE reviews each sample study for accuracy and performs any restratification, if necessary. This review process is done in general for new studies and periodically for restratification every few years. Restratification uses the Dalenius-Hodges and Neyman Allocation techniques to derive a new sample study for a rate class. A new random sample is then selected and new IDR meters are put in place.

For census studies, the customer composition of each rate class is updated every month to ensure full representation.

B. Residential Distributed Generation

Q. IS EPE SUPPLYING ANY SAMPLE STUDIES FOR PROPOSED NEW RATE CLASSES IN THIS FILING?

A. Yes. EPE performed a sample study for the Texas residential customers who have installed rooftop solar. The study provides data about the different load characteristics of these residential DG customers compared to residential customers (non-DG). Cost of service results for DG are summarized by EPE witness Adrian

Hernandez, and the rate design results of DG are summarized by EPE witness Manuel Carrasco.

Q. HOW DOES THE SAMPLE STUDY FOR THESE CUSTOMERS COMPARE TO YOUR OTHER SAMPLE STUDIES?

A. The sample for the residential DG load study was designed using the Dalenius-Hodges and Newman allocation techniques. This is the same methodology used for all the other sample load studies in place. EPE began analyzing its residential rooftop solar customers in early 2013. Initially, the Company used a 12 Coincident Peak ("CP") model that required 19 customers to be sampled in Texas. Two IDR meters, one bi-directional and a Renewable Energy Credit ("REC") meter, were placed on a random set of residential DG customers in order to gather interval demand data. Given the growth of these customers in both numbers and average size of their systems, EPE expanded the sample size to achieve a 4CP model in January 2014 and further expanded to a 1CP model in May 2015. As of the end of the Test Year, EPE had 57 customers in its residential DG load study for Texas. Because EPE allocates cost on the basis of a 1CP model, the load study provides a statistically robust and valid estimate of EPE's system peak.

Q. DOES THE STUDY PROVIDE DATA TO COMPARE THE USAGE PROFILE FOR RESIDENTIAL DG CUSTOMERS WITH THAT OF RESIDENTIAL CUSTOMERS?

A. Yes. The usage profile for residential DG customers is noticeably different than that of the usage profiles of residential customers. Figure GN-1 below compares the delivered load profile for residential DG customers to their total household load profile. The total household load represents the total consumption of residential DG customers regardless of their solar production.

Figure GN-1

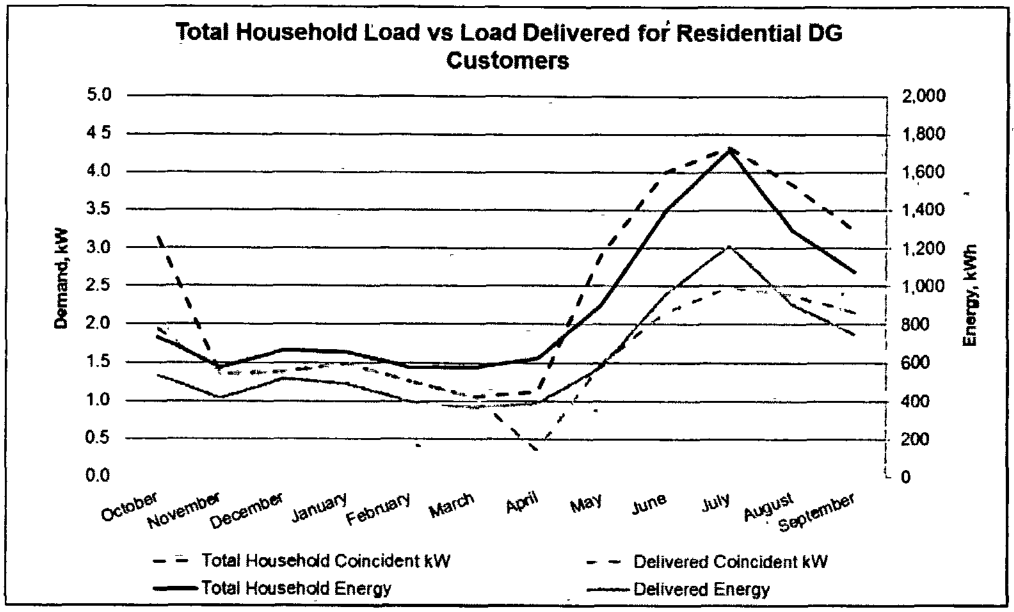

Figure GN-1 uses the interval data from the residential DG bi-directional and REC meters to calculate each customer's total household consumption. It shows a significant decrease in both coincident demand and energy delivered for residences that become residential DG customers. However, we can also compare the delivered load profile of residential DG customers to the load profile of a residential strata. Figure GN-2, below, compares the delivered load profile for residential DG customers to the delivered load profile of residential customers in Strata 4. Strata 4 from the Texas Residential load study was chosen because the total household load of residential DG customers closely follow the consumption patterns of the residential customers that fall in this strata. Figure GN-2 shows similar usage patterns to those in Figure GN-1.

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Figure GN-2

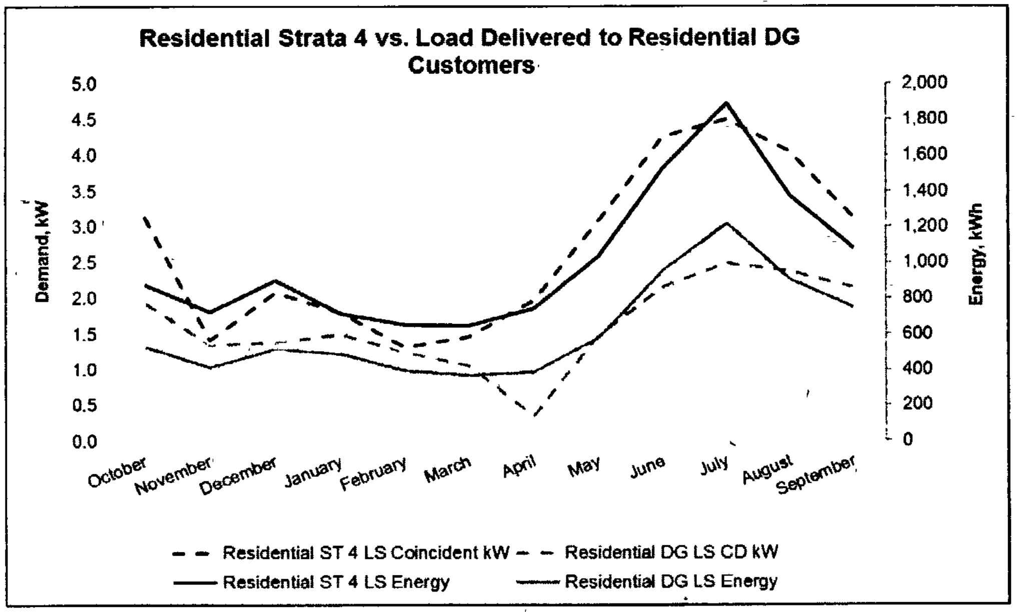

Figure GN-3, below, compares the hourly delivered load profile for residential DG customers to the hourly delivered load profile of residential customers in Strata 4 during the 4CP months of June through September of 2016. This figure shows that the summer usage patterns of both customer groups have distinct consumption characteristics. At the time of the 2016 system peak, consumption was lower for residential DG customers compared with the residential customers in Strata 4.

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Figure GN-3

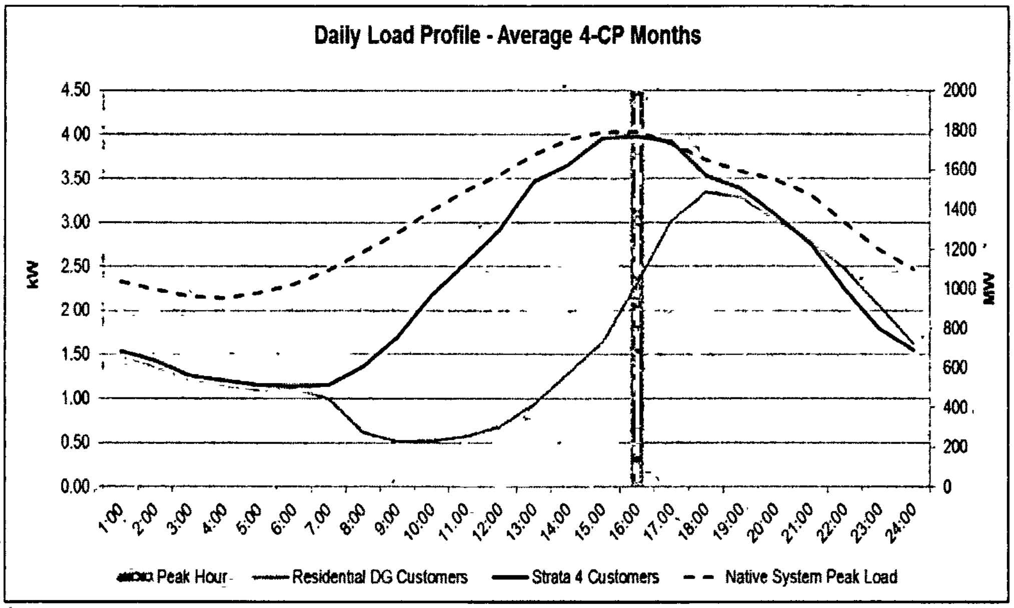

Figure GN-4, below, compares the hourly delivered load profile for residential DG customers to the hourly delivered load profile of residential customers in Strata 4 during the December 2015 peak day for EPE (December 15, 2015). Figure GN-4 shows that the usage patterns of both customer groups have distinct daily consumption characteristics over a winter month. Consumption patterns between the two groups vary over the day, but they do move toward one another during the peak hour.

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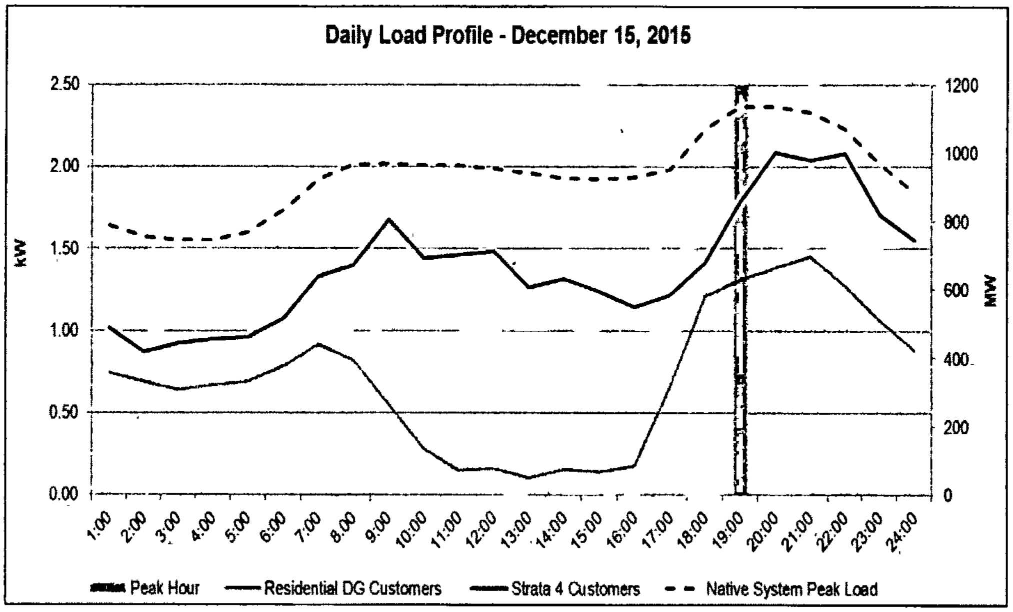
Figure GN-4



The daily peak graphs above, Figures GN-3 and GN-4, highlight that the usage patterns of both customer groups have distinctly different daily consumption characteristics in both the summer and winter months. Consumption patterns between the two groups vary over the day, but converge during the evening hours (after approximately 6pm). As seen above in Figures GN-3 and GN-4, the evening period is a time where native system peak demand is still high. The daily consumption patterns of residential DG customers are more volatile than residential customers due to their ramp up of energy consumption in the late afternoon to early evening hours. The volatility in the delivered load profile of residential DG customers is highlighted by their monthly load factors, as shown in Figure GN-5 below.

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Figure GN-5

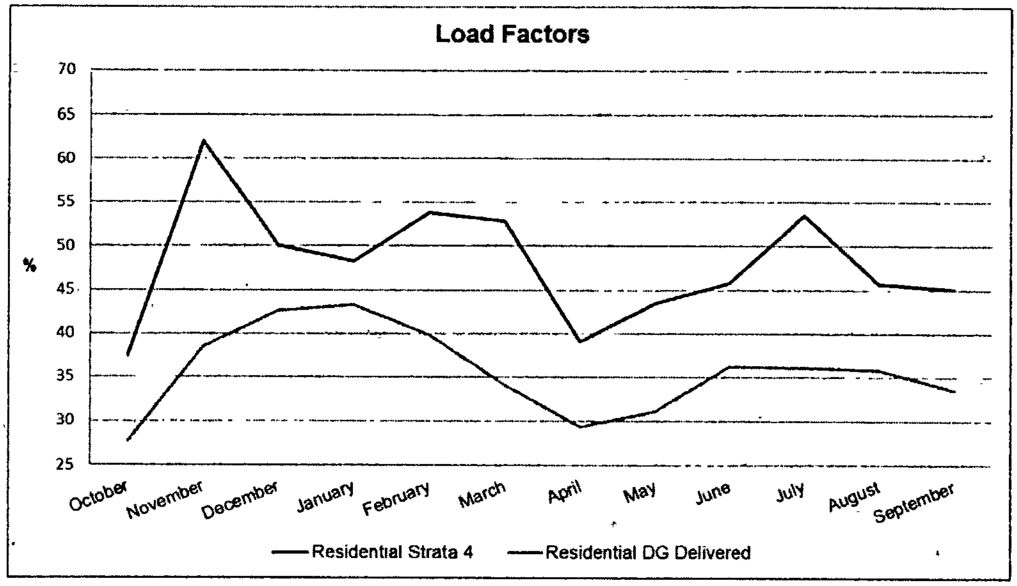

Figure GN-5 has the monthly load factors for both customer groups. As expected, the lower monthly load factor for every month comes from the more volatile group of residential DG customers.

Q. DO RESIDENTIAL DG CUSTOMERS MAINTAIN THEIR REDUCTION IN CONSUMPTION DURING PERIODS OF HIGH SYSTEM PEAK DEMAND?

A. No. Residential DG customers, as seen above in Figures GN-3 and GN-4, ramp up their consumption in the late afternoon to early evening. During this time period, EPE continues to serve a high native system peak demand. Figure GN-6 isolates the average DG system's generation profile and compares it to EPE's hourly native system peak profile for the native system peak day on July 14, 2016.

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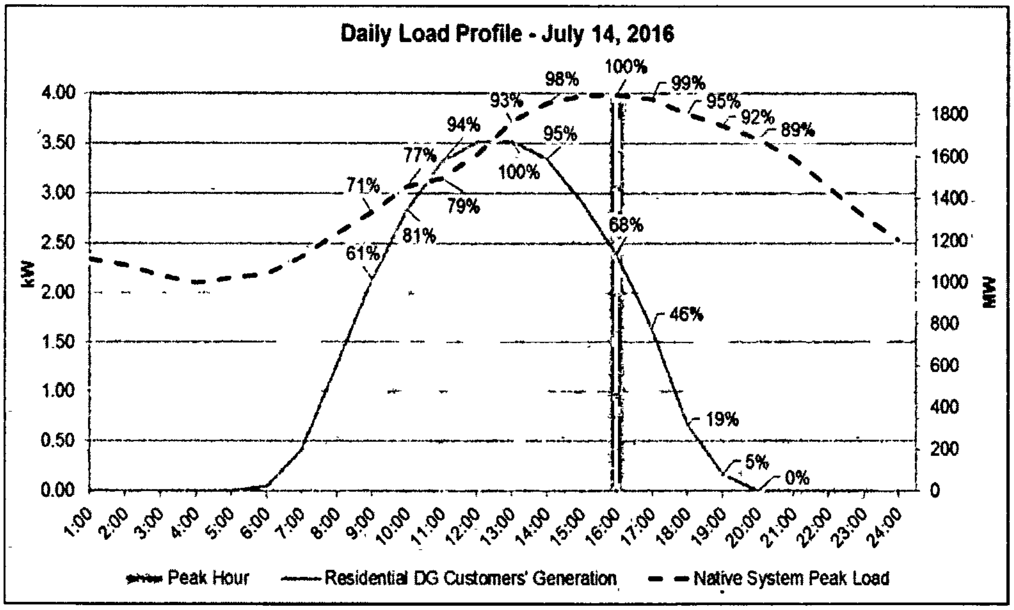
Figure GN-6



As you can see from Figure GN-6, the average DG system production drops significantly after it reaches its maximum output at 13:00 hours. However, EPE must serve the drop in the output of the DG systems while the native system peak demand remains at high levels for several hours. In the example above, the average residential DG system produces 68 percent of its maximum daily output at the time of EPE's system coincident peak (16:00 hours). Output continues to decline until the average residential DG system produces 0 percent of its daily maximum output at 20:00 hours. At 20:00, EPE is still serving 89 percent of the load it had at the time of the coincident peak.

Q. HAVE YOU PERFORMED ANY ADDITIONAL ANALYSIS ON THE PROPOSED RESIDENTIAL DG CUSTOMER CLASS?

A. Yes. Exhibit GN-7 provides further analysis on the comparison between residential DG and residential customers load characteristics. Using various measures, Exhibit GN-7 shows that the residential DG customers are markedly different from residential customers. The significantly different usage characteristics of residential DG customers support the need for these customers to be moved into a separate class. EPE's residential DG rate design proposals are summarized by EPE witness Schichtl.

C. City and County Customers

Q. HAVE YOU PERFORMED AN ANALYSIS TO COMPARE THE USAGE PROFILE OF THE CITY AND COUNTY CUSTOMER CLASS TO OTHER CUSTOMER CLASSES?

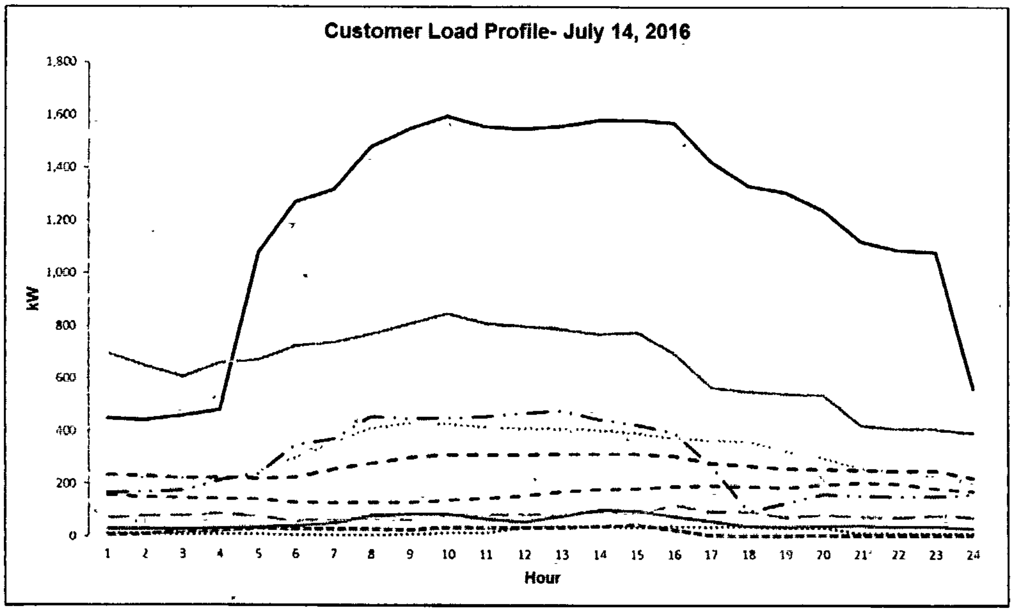
A. Yes. Exhibit GN-8 is an in-depth analysis of the usage characteristics of the current customers in Texas Rate 41 City and County Service ("Rate 41") compared to the usage characteristics of the customers under existing EPE rate classes, i.e., Texas Rate 02 Small General, Texas Rate 24 General Service, and Texas Rate 25 Large Power Service.

Q. WHY DID YOU CONDUCT THE ANALYSIS IN EXHIBIT GN-8?

A. I conducted the analysis to examine the similarity of usage characteristic of current Rate 41 customer types to customers under existing Rates 02, 24 and 25. As shown in Figure GN-7 below, customers in Rate 41 have usage characteristics that are very different from one another. This is due to the fact that they are in Rate 41 simply because of their status as a public school or a municipal/county government agency and not because of their load characteristics, as is the case with most tariffs. Rate 41 is closed to new customers. The only criterion for being placed on Rate 41 when the rate was open was for customers to belong to a public school district or a municipal/county government agency. A Rate 41 customer is not required to meet any energy consumption or maximum demand conditions. New public school facilities and municipal/county government entities are placed into the applicable existing EPE tariff for which they qualify, such as Small General Service, General Service, and Large Power Service depending on the type of consumption that they expect to have. The minimum energy and/or demand criteria for each rate are specified in each tariff.

Figure GN-7 below shows the load profile for 10 randomly sampled customers in the Texas Rate 41 sample study for the system peak day in the Test Year, July 14, 2016:

Figure GN-7



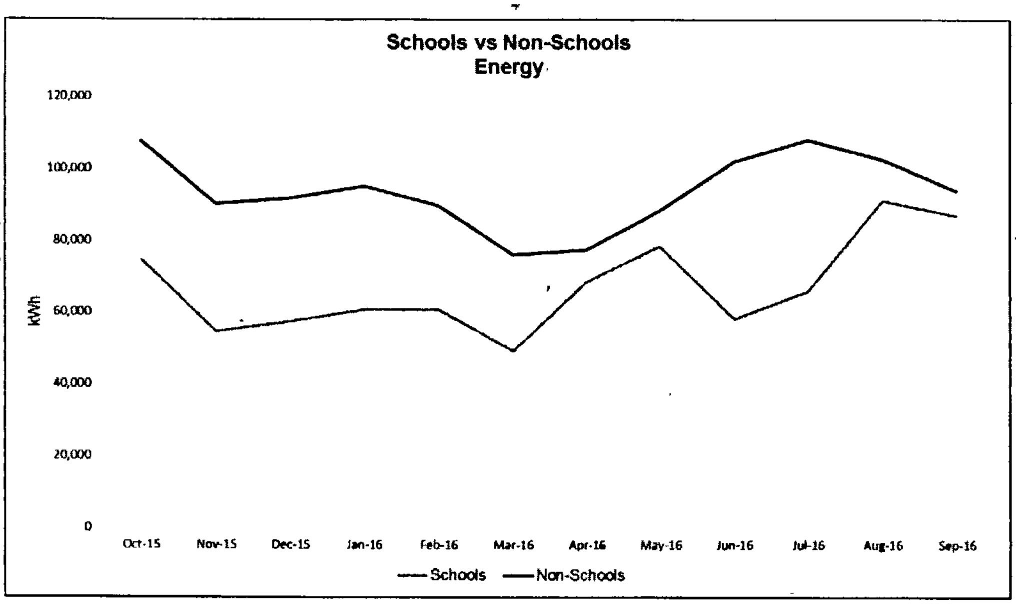
Q. WHAT DOES THE ANALYSIS IN EXHIBIT GN-8 SHOW?

A. The analysis demonstrates that customers currently under Rate 41 have usage patterns that are similar to the customers in other EPE rate classes, specifically Small General Service, General Service, and Large Power Service.

Q. DID YOU ALSO ANALYZE PUBLIC SCHOOL LOAD?

A. Yes. EPE also performed a separate analysis on the consumption patterns of public schools in the Rate 41 sample study in Exhibit GN-8. The analysis found that the pattern of school energy consumption was similar to EPE's non-school customers (existing sampled Rate 41 customers that are not identified as a building used as a school) for a majority of the year. As might be expected, on average, schools lowered their consumption in the early part of the 4CP (June and July) period, when schools close or are less busy due to the summer break. However, schools increased their loads over the second half of the critical peak period (August and September). Figure GN-8, below, shows the monthly energy consumption of our sample schools compared to our sampled non-school customers in Texas Rate 41.

Figure GN-8



However, consumption patterns of public school's various peak demand measures were more volatile than EPE's non-school customers and therefore were not highly correlated to EPE's non-school customers. For a detailed demand analysis of sampled schools compared to non-schools in Rate 41, see Exhibit GN-8.

Q. CAN YOU SUMMARIZE YOUR FINDINGS FROM THE RATE 41 ANALYSIS?

A. Yes. EPE's analysis shows that the usage profiles of existing customers in Texas Rate 41 are similar to the usage profiles of customers in other existing rates for which Rate 41 customers would qualify in the absence of Texas Rate 41. The usage characteristics of current Rate 41 customers are very different from each other.

The only subgroup of customers in Rate 41 that would benefit from further analysis would be the schools subgroup to determine if they are indeed a different group of customers, such as residential DG.

While there may be justification to move current Rate 41 customers to their appropriate rate, it is my understanding that the Company will not seek to move existing Rate 41 customers at this time pending further analysis on schools. EPE'S Rate 41 rate design proposals are summarized by EPE witness Schichtl.

D. <u>Jurisdictional Allocation</u>

Q. HOW ARE ENERGY AND DEMAND ALLOCATED BETWEEN JURISDICTIONS?

A. Energy and demand data by rate class are used to estimate annual and monthly system coincident demand by rate class and jurisdiction. New Mexico load data are gathered from substations and feeders in New Mexico and along the Texas-New Mexico state line. The New Mexico load contribution for each substation is updated on an annual basis. The total New Mexico and RGEC coincident demand is subtracted from total system demand to determine Texas coincident load. Maximum and coincident demand by rate class is determined by using billed energy and the estimated load and coincidence factors from the load studies. Energy and demand losses are applied in this model using the most current loss study.

Q. HAS EPE MADE ANY NOTEWORTHY CHANGES IN ITS ALLOCATION METHODOLOGY FROM ITS LAST TEXAS RATE CASE FILING IN DOCKET NO. 44941?

A. Yes. EPE has made two noteworthy changes to its allocation methodology that differs from Docket No. 44941. The first is a change to the load factor used in EPE's calculation of the 4CP-Average and Excess ("4CP-A&E"). In the past, EPE has employed the use of an average load factor based on the four critical months (June-September) in its calculation of the 4CP-A&E. EPE now employs a load factor in its calculation of the 4CP-A&E based on the single highest peak demand measured during the Test Year (1CP).

The second change involves using a system load factor in its calculation of the 4CP-A&E for both jurisdictional and class/retail allocators. In the past EPE used a system load factor in its calculation of the 4CP-A&E for only jurisdictional allocation. The Texas class/retail load factor was used in its 4CP-A&E calculation for allocating capacity-related production at the class/retail level.

Q. WHY HAS EPE MADE THE TWO CHANGES ABOVE?

A. The first change, regarding a move from a 4CP to 1CP load factor, follows the Commission's Final Order in a recent Southwestern Public Service Company ("SPS") rate case, Docket No. 43695. In that case, the Commission found that the use of a 1CP factor was more consistent with how SPS planned and built its generation and transmission systems.

The second change, regarding the use of a system load factor to calculate the 4CP-A&E for both jurisdictional and class/retail allocators, follows the Commission's Final Order in a recent Southwest Electric Power Company ("SWEPCO") rate case; Docket No. 40443. In that case, the Commission found that since SWEPCO's generation is built to meet system needs based on analysis of the system loads, it is reasonable to allocate costs using the system load factor.

I believe both these changes are reasonable and are in line with recent orders by the Commission.

E. Peak Demand

Q. WHAT IS THE TREND OF THE TOTAL SYSTEM PEAK DEMAND?

A. EPE is a summer peaking utility. This means that EPE's system will experience a significantly higher load during the day between the months of May to September than it experiences at other times of the year. In addition, demand in the off-peak hours during the summer decreases significantly due to the mild weather in El Paso. To efficiently meet peak demand, EPE's generation must be readily available during daytime summer conditions and able to cycle or shut down completely during off-peak periods (e.g., nights, weekends and winter) and turn on without limit as soon as needed. Over the past ten years the system peak demand has had a CAGR of 2.7 percent while native energy has had a CAGR of 1.4 percent. This has resulted in a decreasing trend in EPE's system load factor. The historical demand and native system energy for the EPE system is presented in Exhibit GN-6.

Over the past decade the EPE system load factor has fallen. Overall, the system load factor dropped from 59.8 percent in 2006 to 53.7 percent in 2015. The primary factors behind this long-term decline in system load factor include the decline in manufacturing activity and the increase in the saturation of central refrigerated air conditioning units in the residential class.

Refrigerated air conditioning units use significantly more electricity than evaporative cooling units. The demand for electricity from refrigerated air conditioning units tends to be highest during hot summer days, when they cycle on and off in response to hot temperatures. In contrast, evaporative air conditioners have limited cycling. This contributes to a downward trend in the system load factor, which means that demand grows faster than sales. Over time, this results in swings in demand that become more pronounced during the summer months, thus requiring additional generation to meet this demand.

V. WEATHER NORMALIZATION

Q. WHY DID EPE UTILIZE A WEATHER ADJUSTMENT IN THE ANNUALIZATION PROCESS?

A. The weather adjustment provides a level of sales that can be expected during a year with average weather. EPE needs to adjust energy sales based on the weather to avoid over- or understating the level of sales that could be expected during a year with average weather. The total weather adjustment for Texas retail customers is a decrease of 17,793,008 kWh (-0.29 percent) from total Texas retail Test Year sales of 6,175,132,723 kWh. Weather can have a profound impact on the month-to-month fluctuations in EPE's system energy sales. This is due in large part to the operation of heating and cooling equipment that is weather sensitive.

In EPE's service area, the adoption of central refrigerated air conditioning is increasing. Central refrigerated air conditioning equipment is replacing evaporative cooling equipment in residences and commercial establishments. Additionally, new residential construction projects include the use of refrigerated air units. As a result, EPE's load has become more weather sensitive.

Q. WHY DOES EPE USE WEATHER STATIONS FOR BOTH EL PASO AND LAS CRUCES?

A. An analysis of historical heating degree days ("HDD") and historical cooling degree days ("CDD") for El Paso and Las Cruces revealed that there are climate differences between the two locations. I note this in Exhibit GN-3. These degree days measure the fluctuations in daily average temperature below or above the designated base temperature (65 degrees Fahrenheit). Temperatures below the designated base temperature lead to increased use of heating appliances and are, therefore, referred to as heating degree days. Conversely, fluctuations in daily average temperature above the 65 degree base temperature lead to greater use of air conditioning and are referred to as cooling degree days.

Despite the fact that El Paso and Las Cruces are located in a dry desert climate and are less than 50 miles apart, they have some climate differences that make it important to match weather data at both locations to analyze their respective energy sales. Even though the temperatures in both cities tend to move in the same direction relative to each other, El Paso tends to be warmer than Las Cruces. Over the last 10 years, Las Cruces has consistently had fewer annual CDD than El Paso.

Given these consistent differences in weather patterns between the two cities, EPE has concluded that it is appropriate to use two different weather sites for our analysis.

A. <u>Description of EPE's Weather Normalization Adjustment</u>

Q. WHY HAS EPE MADE WEATHER NORMALIZATION ADJUSTMENTS TO THE ENERGY OF THE VARIOUS RATE CLASSES?

A. Adjustments for such fluctuating temperature conditions are made to ensure that the kilowatt-hour sales levels, upon which rates are based, neither over-recover nor under-recover the utility's allowed cost of service. Kilowatt-hour sales were adjusted to normalize Test Year sales for those rate classes whose use of electricity is sensitive to temperature conditions. During a given period, such as the Test Year, temperature conditions may be warmer or colder than normal. As a result, sales of electricity may be higher or lower than the level that will normally occur.

Q. HOW WERE EPE'S WEATHER NORMALIZATION ADJUSTMENTS MADE?

A. EPE prepared statistical models that measure customer responsiveness to temperatures for all rate classes. Only those econometric models that displayed statistically significant effects to fluctuations in temperature were included in EPE's weather adjustment. EPE found a total of seven such econometric models in Texas.

The seven individual Rate Class models are:

- Rate 01 Residential,
- Rate 02 Small General Service,
- Rate 11 Municipal Pumping,
- Rate 22 Irrigation,
- Rate 24 General Service;
- Rate 31 Military Reservation Service, and
- Rate 41 City and County Service.

Q. WHICH RATE CLASSES WERE EXCLUDED FROM WEATHER NORMALIZATION ADJUSTMENTS?

A. Weather normalization adjustments were not made to lighting classes or to Large Commercial and Industrial customer classes, since these customers' uses of electricity are not sensitive to fluctuations in temperature. Further, no weather normalization adjustment is proposed for RGEC since EPE does not have access to end-user information for this wholesale customer.

Q. WHAT IS THE PROCESS FOR CALCULATING WEATHER NORMALIZATION ADJUSTMENTS?

A. Weather normalization adjustments were calculated in a three-step process. First, linear regressions were employed to quantify the influence that factors such as CDD, HDD, income, and other variables have upon monthly electric consumption. A number of linear regression models were examined, and the models were tested for statistical strength and reasonableness.

In the second step of calculating the weather normalization adjustments, the coefficients of the regression equations were translated into monthly kWh adjustments for the Rate Classes. The regression coefficients for the explanatory variables in each regression equation equal the change in the dependent variable (kWh usage) associated with a one unit change in the explanatory variable. Thus, the regression coefficients for CDD provide the changes in monthly usage per customer associated with a one CDD change. Similarly, the regression coefficients for HDD provide the changes in monthly usage per customer associated with a one HDD change. Multiplying the degree day regression coefficient by the difference between the normal number of degree days and the Test Year period actual degree days in a month produces the amount by which Test Year period kWh varied from kWh use under normal temperature conditions. Exhibit GN-5 shows these calculations.

In the third step, for the residential class, the above kWh per customer impact is multiplied times the number of monthly customers. The residential rate classes are estimated on a use per customer basis because customers display homogenous consumption. The kWh weather impact estimate for these classes is based on a per customer basis so multiplying by the number of customers in that month is necessary to get a total weather effect value. Allocation of the monthly weather normalization adjustments are provided in Exhibit GN-5.

Q. HOW DOES EPE CALCULATE NORMAL WEATHER?

A. EPE uses a 10-year average of monthly National Oceanic and Atmospheric Administration ("NOAA") HDDs and CDDs, adjusted for billing cycles, as a proxy for future average weather conditions. EPE relies on the accuracy and acceptance of NOAA data as being the international standard.

NOAA is a federal agency that monitors climate and collects and publishes local weather pattern data. NOAA calculates HDD and CDD data that are used by forecasters to estimate the impact of weather on energy sales and load. Because CDD and HDD are recorded on a calendar month basis while booked month sales are recorded over 18 billing cycles that normally include portions of two calendar months, it was necessary to transform these calendar month variables into variables that correspond to EPE's billing cycles. This transformation was accomplished through the use of two month moving average CDD and HDD variables.

Weather fluctuates from year to year. Some years are hotter than others and some are cooler. But over a longer period of time, for example 10 years, any large weather variation that occurs in one year is tempered in the analysis over the time frame.

Q. OTHER THAN CDD AND HDD, WHAT OTHER EXPLANATORY VARIABLES WERE EMPLOYED IN MODELING CONSUMER USE OF ELECTRICITY?

A. In addition to including CDD and HDD variables, each weather model was structured to incorporate economic and/or demographic variables that are likely to affect the use of electricity by the class being modeled.

Q. WERE THE MODELS TESTED FOR STATISTICAL ACCURACY AND GOODNESS OF FIT?

A. Yes. All models met statistical requirements for logical consistency in terms of the explanatory variables employed, signs of the coefficients, and consistency of results using alternative model specifications. In addition, the models were tested for significance of the independent variables as well as goodness of fit.

The adjusted coefficient of determination ("R^2") for the Texas regression models ranged from 70.1 percent to 96.0 percent. The coefficient of determination measures the proportion of the change in the dependent variable (kWh use) that is explained by the exogenous, or independent, variables. The goodness of fit of the models employed in the weather normalization adjustments is indicated by the R^2 of the model equations. The regression equations model customer use of energy over time and are, as such, time series regressions. Time series regressions are frequently affected by the presence of a serial correlation error term, also known as autocorrelation. Autocorrelation is caused by a lack of independence of an equation's error terms, which may result in inflating the R^2 of the model. Therefore, the models were adjusted for the presence of autocorrelation terms when necessary.

The coefficients for the independent variables in each model are significant at a 95 percent confidence level. A 95 percent confidence level indicates a high degree of confidence in the estimated kWh impact of temperature fluctuations. In summary, the statistics of the models indicate that we have confidence in the degree day and economic variables employed in the models, and that these variables do an excellent job of explaining changes in energy use.

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Q. HOW WERE THE RESULTS OF THE REGRESSION EQUATIONS TRANSLATED INTO WEATHER NORMALIZATION ADJUSTMENTS FOR EACH AFFECTED CLASS?

A. As described previously in my testimony, the coefficients of the CDD and HDD variables represent the change in energy use that corresponds to a one-degree day change in temperature. Therefore, the product of multiplying the CDD and HDD coefficients by the differences between actual Test Year degree days and 10 year average degree days provides the amount by which customer use of electricity has been affected by abnormal temperatures. For example, for the Texas Residential model, the July 2016 weather normalization adjustment was calculated as follows:

Normal CDD		597 CDD
Actual CDD	-	667 CDD
Difference CDD		(70) CDD
July CDD Coefficient	X	0.60373 kWh/CDD/Customer
Difference X Coefficient		(42) kWh/Customer
Number of Customers	X	277,518 Customers
Adjustment		(11,728,216) kWh

Note: Due to rounding, the totals in the example above do not add to the total adjustment.

All other months were calculated in the same manner using data specific to that month. The example above employs a monthly use per customer as the dependent variable. The models that employ total Rate Class kWh as the dependent variable do not have to multiply the resulting change in kWh by the number of customers in the class. Once the monthly kWh use for the weather sensitive classes was developed, the weather adjusted monthly kWh use was further adjusted for year-end customer growth as explained in the direct testimony of EPE witness Carrasco. Please refer to Exhibit GN-5 for the monthly calculations by rate class described previously.

Q. WHAT IS A NOAA NORMAL FOR COOLING DEGREE DAYS AND HEATING DEGREE DAYS?

A. Since the number of degree days can vary significantly on a year-to-year basis, NOAA provides normal HDD and CDD estimates that serve as a proxy for the number of degree days that would be expected to occur during a year with normal weather. To calculate the normal CDD and HDD for a particular month, NOAA uses the 30-year average high and low for each day of the month to calculate a daily CDD or HDD. These daily CDD and HDD are then summed up for the month to arrive at the monthly normal CDD and HDD.

Q. WHY DOES EPE USE 10-YEAR AVERAGE DEGREE DAYS FOR NORMAL WEATHER INSTEAD OF THE NORMAL DEGREE DAYS PUBLISHED BY NOAA?

A. Using a 10-year average provides a reasonable time frame to encompass cyclical temperature patterns lasting over several years and to smooth out the impact of extreme ranges of temperature that may randomly occur from year to year and that cannot reasonably be expected to be continuously repeated. In addition to being able to encompass cyclical temperature patterns, its smaller size is more reflective of current weather patterns. In addition, the NOAA normal data is only updated every 10 years, with the last update in 2010.

Figure GN-9 provides a graphic display of actual CDD (not adjusted for billing) in El Paso during the Test Year as well as the average number of CDD using a 10-year average. Note that although the Test Year CDD and the 10-year average have a similar shape there is a significant difference in the month of July. During the Test Year, July is significantly above the 10-year average while August is well below the 10-year average. Please refer to Exhibit GN-4 for the weather data described above. The Commission has found 10 years to be a reasonable basis for the weather adjustment.

Figure GN-9

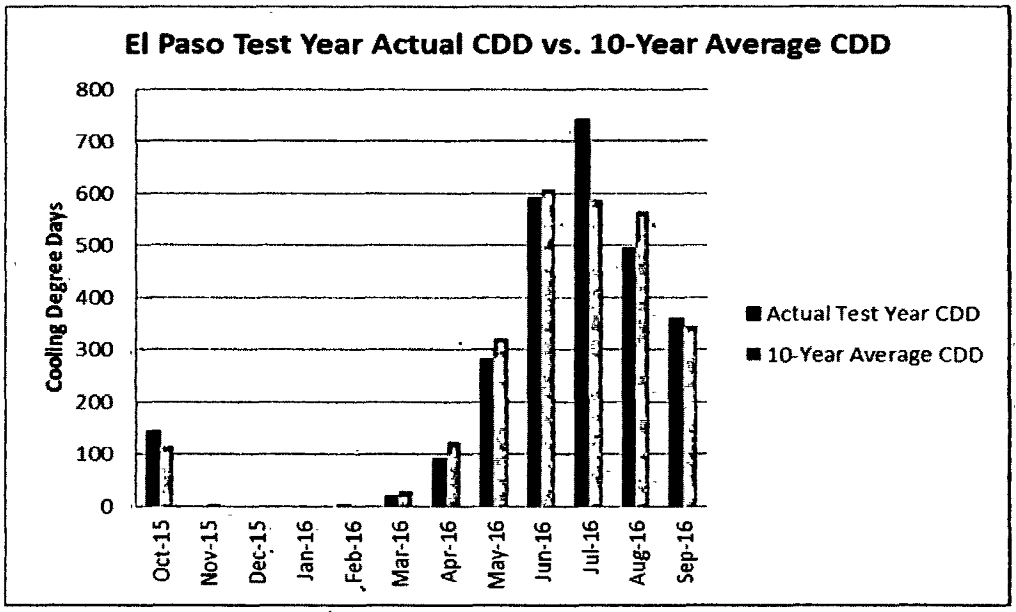

Figure GN-10 provides a graphic display of actual HDD (not adjusted for billing) in El Paso during the Test Year as well as the average number of HDD using a 10-year average. Note that although the Test Year HDD and the 10-year average have a similar shape February and March are significantly below the 10-year average. Please refer to Exhibit GN-4 for the weather data described above.

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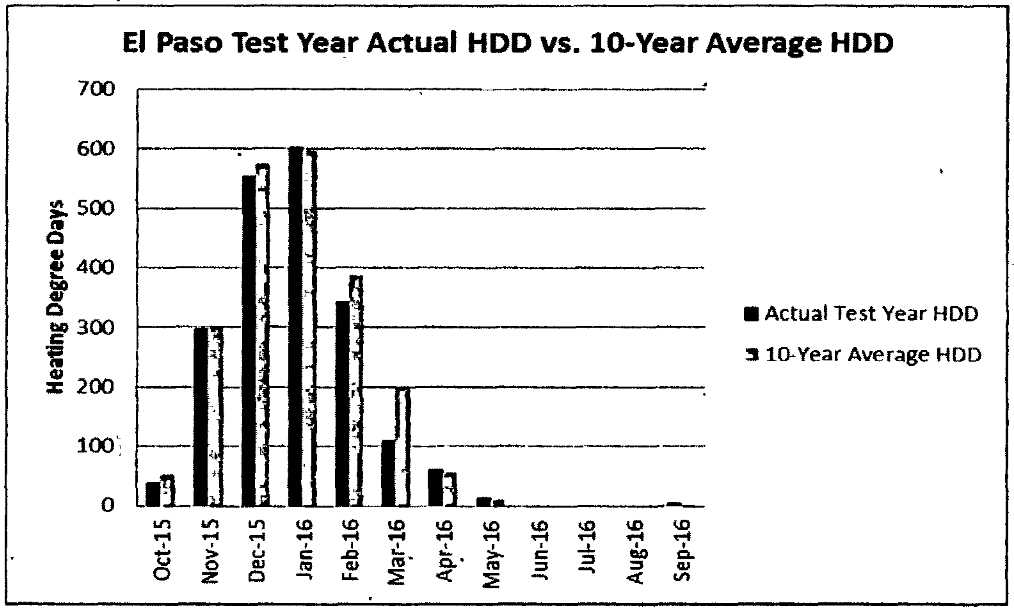
Figure GN-10



Q. HOW DO THE TEST YEAR PERIOD ACTUAL CDD AND HDD FOR EL PASO COMPARE TO NORMAL (10-YEAR AVERAGE) CDD AND HDD FOR THAT RECORDING LOCATION?

A: Actual Test Year (not adjusted for billing) CDD for El Paso are 1.3 percent higher than the 10-year average CDD and actual Test Year HDD (not adjusted for billing) are 7.0 percent lower than the 10-year average HDD. Figure GN-11 below compares the Test Year actual CDD and HDD against the 10-year average CDD and HDD.

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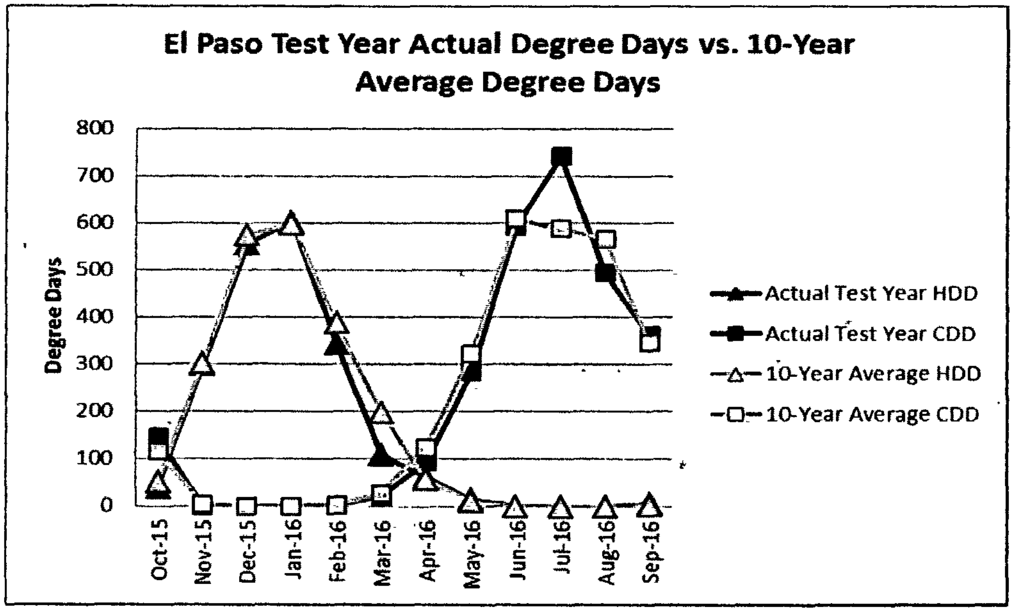
Figure GN-11



Q. WHAT WAS THE EFFECT OF THE WEATHER ADJUSTMENT ON KWH SALES FOR TEXAS RETAIL CUSTOMERS?

A. The weather normalization adjustment reflects a reduction in kWh sales to account for the slightly warmer weather during the Test Year. The reduction is necessary to restate sales at more normal levels that can be reasonably anticipated when new rates are placed into effect. The total weather adjustment for Texas retail customers is a decrease of 17,793,008 kWh (-0.29 percent) from total Texas retail Test Year sales of 6,175,132,723 kWh.

This adjustment is provided for each affected rate class by month on Exhibit GN-5 of EPE's rate filing package. In addition, Exhibit GN-5 also provides the calculation of the monthly weather normalization adjustments for each rate class.

VI. SUMMARY AND CONCLUSIONS

Q. IS THE LOAD FORECAST REASONABLE?

A. Yes. EPE's econometric forecast methodology, using economic and demographic explanatory variables, is an established industry standard. The econometric models used in the forecasts are sound in theory and they are statistically significant. In addition, sound professional judgment was exercised in developing the forecasts for rate classes that otherwise did not lend themselves to econometric modeling. Individual customer forecasts for large commercial and street lighting as well as sales forecasts for distributed generation were based on recent trends and known or reasonably predictable changes in consumption levels.

The 2016 long-term forecast exhibits a 10-year CAGR for native system energy and native system demand of approximately 1.4 and 1.6 percent respectively. These growth rates are consistent with recent trends and the economic growth projections for our service territory. In sum, the source data and forecast methodologies yield a reasonable estimate of sales and demand for this filing.

Q. ARE THE WEATHER NORMALIZATION ADJUSTMENTS THAT YOU SPONSOR FAIR AND REASONABLE?

A. Yes, they are both fair and reasonable. The economic models used to develop the adjustments employ standard industry practices, and the models have a high level of statistical confidence. Furthermore, the weather normalization adjustments fairly and reasonably reflect the impact of slightly warmer weather during the Test Year. The total weather adjustment for Texas retail customers is a decrease of 17,793,008 kWh (-0.29 percent) from total Texas retail Test Year sales of 6,175,132,723 kWh.

Q. ARE YOUR RECOMMENDATIONS FOR RESIDENTIAL DG AND EXISTING RATE 41 CUSTOMERS REASONABLE?

A. Yes. Various measures show that the residential DG customers are markedly different from residential customers. The significantly different usage characteristics of residential DG customers support the need for these customers to be moved into a separate class.

Existing customers in Texas Rate 41 have usage characteristics that are very different from each other. The usage profiles of these customers are similar to the usage profiles of customers in other existing rates. This supports the need for these customers to be moved into the applicable rate class. The only subgroup of customers in Rate 41 that would benefit from further analysis would be the schools subgroup to determine if they are indeed a different class of customers.

While the analysis provided in my testimony justifies moving most current Rate 41 customers to their appropriate rate, it is my understanding that the Company will not seek to move existing Rate 41 customers at this time, pending further analysis on schools. EPE'S Rate 41 rate design proposals are summarized by EPE witness Schichtl.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SCHEDULES SPONSORED OR CO-SPONSORED BY G. NOVELA

Schedule	Description	Sponsorship
H-12.1	SUPPLY AND LOAD DATA	Co-Sponsor
H-12.5a	LINE LOSSES & SYSTEM'S OWN USE	Co-Sponsor
H-12.5f	ON SYSTEM SALES (WHOLESALE & RETAIL)	Sponsor
H-12.6a	MONTHLY MINIMUM AND PEAK DEMAND	Sponsor
H-12.6b	MONTHLY LOAD DURATION CURVE	Sponsor
H-12.6c	ANNUAL LOAD DURATION CURVE	Sponsor
O-1.3	UNADJUSTED TEST YEAR DATA BY RATE CLASS	Sponsor
O-1.4	MONTHLY ADJUSTED TEST YEAR DATA BY RATE CLASS	Sponsor
O-1.6	SYSTEM LOAD FACTOR	Sponsor
O-1.9	PEAK DEMAND BY RATE CLASS	Sponsor
O-2.1	MODEL INFORMATION	Sponsor
O-2.2	MODEL DATA	Sponsor
O-2.3	RAW MODEL DATA	Sponsor
O-6.1	UNADJUSTED kWh SALES BY MONTH OF THE TEST YEAR	Sponsor
O-6.2	ADJUSTED kWh SALES DATA	Sponsor
O-7.1	SALES AND DEMAND DATA	Sponsor
O-7.2	HISTORICAL SALES DATA	Sponsor
O-8.1	HISTORICAL WEATHER DATA	Sponsor
O-8.2	HISTORICAL WEATHER DATA AFTER WEIGHTING & BILLING CYCLE ADJUST'S	Sponsor
O-8.3	NORMAL HEATING AND COOLING DEGREE DAYS	Sponsor
O-8.4	65 DEGREE F BASE TEMPERATURE RESPONSES	Sponsor
O-9.1	RATE YEAR FORECAST MODEL INFORMATION	Sponsor
O-9.2	MODEL DATA	Sponsor
O-9.3	RAW MODEL DATA	Sponsor
O-10.1	HISTORICAL DATA	Sponsor
O-10.2	PERSONAL INCOME DATA (NOMINAL PERSONAL INCOME)	Sponsor
P-9	DEMAND AND ENERGY LOSS FACTORS	Sponsor
Q-5.1	DEMAND DATA BY CUSTOMER CLASS	Sponsor
Q-5.2	DEMAND, CONSUMPTION, AND CUSTOMER DATA BY STRATA	Sponsor
Q-5.3	DEMAND ESTIMATES METHODOLOGY	Sponsor

EL PASO ELECTRIC COMPANY
2016-2025 DEMAND AND ENERGY FORECAST
April 7, 2016

Summary

ENERGY (GWH)	2015 (1)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	10-YR (6) CAGR
Native System Forecast (NFL) (2)												
Upper Bound		9,472	9,672	9,886	10,088	10,308	10,520	10,737	10,964	11,198	11,444	
Expected:	8,475	8,577	8,751	8,935	9,101	9,283	9,453	9,626	9,807	9,993	10,188	1.9
Lower Bound		7,682	7,830	7,984	8,114	8,258	8,386	8,515	8,649	8,787	8,932	
Less: DG (3)		8	15	23	30	38	45	52	60	67	74	
Less: EE (4)		35	71	106	142	177	212	248	283	319	354	
Native System Energy												
Upper Bound		9,429	9,583	9,749	9,900	10,068	10,226	10,389	10,560	10,737	10,925	
Expected:	8,475	8,534	8,665	8,806	8,929	9,069	9,195	9,326	9,464	9,607	9,759	1.4
Lower Bound		7,639	7,747	7,863	7,958	8,069	8,164	8,263	8,368	8,477	8,594	
Total System Net Energy (5)												
Upper Bound		9,410	9,564	9,731	9,883	10,051	10,210	10,372	10,544	10,722	10,910	
Expected:	8,398	8,525	8,656	8,797	8,920	9,059	9,186	9,317	9,455	9,598	9,750	1.5
Lower Bound		7,640	7,748	7,863	7,958	8,067	8,163	8,261	8,365	8,474	8,591	
DEMAND (MW)												
Native System Forecast (NFL)												
Upper Bound		2,075	2,127	2,176	2,222	2,266	2,318	2,366	2,415	2,459	2,518	
Expected:	1,794	1,818	1,860	1,899	1,934	1,968	2,009	2,046	2,084	2,118	2,165	1.9
Lower Bound		1,561	1,593	1,622	1,646	1,669	1,700	1,726	1,753	1,776	1,813	
Less: DG		2	3	5	6	8	9	11	12	14	15	
Less: EE		5	11	16	21	27	32	38	43	48	54	
Native System Demand:												
Upper Bound		2,068	2,112	2,154	2,192	2,227	2,271	2,310	2,350	2,386	2,435	
Expected:	1,794	1,811	1,846	1,878	1,907	1,933	1,968	1,997	2,029	2,056	2,096	1.6
Lower Bound		1,554	1,580	1,602	1,621	1,639	1,664	1,685	1,708	1,726	1,758	
Total System Demand												
Upper Bound		2,065	2,110	2,152	2,189	2,225	2,268	2,307	2,347	2,383	2,432	
Expected:	1,792	1,809	1,844	1,876	1,905	1,931	1,966	1,996	2,027	2,054	2,094	1.6
Lower Bound		1,553	1,578	1,601	1,620	1,637	1,663	1,684	1,707	1,725	1,757	
Interruptible Load		52	52	52	52	52	52	52	52	52	52	
Upper Bound		2,014	2,055	2,093	2,128	2,162	2,203	2,240	2,279	2,314	2,362	
Expected:	1,792	1,757	1,792	1,824	1,853	1,879	1,914	1,944	1,975	2,002	2,043	1.3
Lower Bound		1,501	1,530	1,556	1,577	1,597	1,625	1,647	1,671	1,691	1,724	

Footnotes.

(1) 2015 are Actual data, Native System Peak occurred on August 6th.

(2) Net For Load is forecasted load before the removal of DG and EE.

(3) Impact from Distributed Generation

(4) Impact from Energy Efficiency.

(5) Total System includes transmission wheeling Losses To Others.

(6) 10-Year Compounded Average Growth Rate.

EL PASO ELECTRIC COMPANY
2026-2035 DEMAND AND ENERGY FORECAST
April 7, 2016

Summary

ENERGY (GWH)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	20-YR (1) CAGR
Native System Forecast (NFL)											
Upper Bound	11,702	11,975	12,256	12,549	12,855	13,162	13,487	13,826	14,176	14,538	
Expected:	10,394	10,611	10,834	11,066	11,309	11,549	11,805	12,072	12,348	12,631	2.0
Lower Bound	9,085	9,247	9,413	9,584	9,763	9,937	10,124	10,319	10,519	10,725	
Less: DG	82	89	96	103	110	117	124	131	138	145	
Less: EE	389	425	460	496	531	566	602	637	673	708	
Native System Energy:											
Upper Bound	11,126	11,340	11,563	11,797	12,044	12,292	12,557	12,837	13,127	13,430	
Expected:	9,923	10,097	10,278	10,468	10,668	10,866	11,079	11,304	11,537	11,778	1.7
Lower Bound	8,719	8,855	8,993	9,139	9,292	9,440	9,601	9,771	9,946	10,127	
Total System Net Energy:											
Upper Bound	11,111	11,326	11,549	11,783	12,030	12,278	12,544	12,824	13,114	13,417	
Expected:	9,913	10,088	10,269	10,459	10,659	10,857	11,070	11,295	11,528	11,769	1.7
Lower Bound	8,716	8,851	8,989	9,134	9,287	9,435	9,596	9,766	9,941	10,122	
DEMAND (MW)											
Native System Forecast											
Upper Bound	2,573	2,630	2,684	2,751	2,816	2,881	2,942	3,020	3,093	3,169	
Expected:	2,209	2,255	2,296	2,352	2,403	2,455	2,502	2,566	2,624	2,684	2.0
Lower Bound	1,845	1,880	1,909	1,952	1,991	2,028	2,062	2,112	2,155	2,200	
Less: DG	17	18	20	21	22	24	25	27	28	30	
Less. EE	59	64	70	75	81	86	91	97	102	107	
Native System Demand:											
Upper Bound	2,480	2,529	2,573	2,631	2,687	2,742	2,794	2,862	2,926	2,993	
Expected:	2,133	2,173	2,207	2,256	2,300	2,345	2,385	2,442	2,494	2,548	1.8
Lower Bound	1,786	1,816	1,841	1,880	1,914	1,948	1,977	2,023	2,062	2,103	
Total System Demand:											
Upper Bound	2,478	2,526	2,570	2,629	2,684	2,739	2,791	2,859	2,923	2,990	
Expected:	2,131	2,171	2,205	2,254	2,299	2,343	2,384	2,440	2,492	2,546	1.8
Lower Bound	1,785	1,815	1,840	1,879	1,913	1,947	1,976	2,022	2,061	2,102	
Interruptible Load:	52	52	52	52	52	52	52	52	52	52	
Upper Bound	2,407	2,455	2,498	2,556	2,610	2,665	2,717	2,785	2,849	2,915	
Expected:	2,080	2,119	2,153	2,202	2,247	2,291	2,332	2,389	2,440	2,494	1.7
Lower Bound	1,752	1,783	1,809	1,848	1,883	1,917	1,947	1,992	2,032	2,072	

Footnotes.

(1) 20-Year Compounded Average Growth Rate

Exhibit GN-3 Historical Weather in Las Cruces, NM and El Paso, TX

	Las Cruces		El Paso		Percent Difference LC vs. EP	
Year	HDD	CDD	HDD	CDD	HDD	CDD
2006	2,511	1,938	2,020	2,457	24%	-21%
2007	2,690	2,024	2,286	2,512	18%	-19%
2008	2,759	1,708	2,188	2,272	26%	-25%
2009	2,657	2,050	2,144	2,768	24%	-26%
2010	2,885	2,066	2,273	2,738	27%	-25%
2011	2,888	2,324	2,402	3,141	20%	-26%
2012	2,483	2,173	2,009	2,876	24%	-24%
2013	2,910	2,102	2,426	2,695	20%	-22%
2014	2,390	2,043	1,900	2,671	26%	-24%
2015	2,599	2,196	2,095	2,839	24%	-23%
Average (2006-2015)	2,677	2,062	2,174	2,697	23%	-23%

Exhibit GN-4 Test Year Degree Days Vs. Normal Weather Degree Days

Line No.	El Paso, TX													
1		2015	2015	2015	2016	2016	2016	2016	2016	2016	2016	2016	2016	Test Year
2		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
3														
4	Cooling Degree Days - Base 65 deg. F. El Paso, Texas													
5	Actual CDD	144	0	0	0	3	20	91	282	592	742	494	360	2,728
6	10 year average	114	4	0	0	2	27	122	322	607	587	565	344	2,694
7														
8	Heating Degree Days - Base 65 deg. F. El Paso, Texas													
9	Actual HDD	38	297	554	602	343	109	61	14	0	0	0	5	2,023
10	10 year average	51	302	573	597	387	197	56	10	0	0	0	1	2,174
11														
12	Las Cruces, NM													
13		2015	2015	2015	2016	2016	2016	2016	2016	2016	2016	2016	2016	Test Year
14		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
15														
16	Cooling Degree Days - Base 65 deg. F. Las Cruces, NM													
17	Actual CDD	106	0	0	0	0	0	25	156	517	642	447	298	2,191
18	10 year average	58	0	0	0	0	2	33	182	481	523	496	280	2,055
19														
20	Heating Degree Days - Base 65 deg. F. Las Cruces, NM													
21	Actual HDD	52	384	676	707	405	208	135	25	0	0	0	3	2,595
22	10 year average	91	370	648	671	467	298	103	22	0	0	0	2	2,672

EXHIBIT GN-4
PAGE 1 OF 1

	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
Actual Weather												
El Paso												
HDD-2MA	19	168	426	578	473	226	85	38	7	0	0	3
CDD-2MA	311	72	0	0	2	12	56	187	437	667	618	427
Las Cruces												
HDD-2MA	26	218	530	692	556	307	172	80	13	0	0	2
CDD-2MA	240	53	0	0	0	0	13	91	337	580	545	373
10-Year Avg Weather	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
El Paso												
HDD-2MA	26	177	438	585	492	292	126	33	5	0	0	1
CDD-2MA	225	59	2	0	1	15	74	222	464	597	576	455
Las Cruces												
HDD-2MA	47	231	510	660	569	383	200	63	12	0	0	1
CDD-2MA	169	29	0	0	0	1	18	108	332	503	510	388
Coefficients	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
TXRT01- Residential	0.5471	0.4227	0.3374	0.4133	0.2646	0.2595	0.5064	0.2271	0.4799	0.6037	0.5958	0.6674
TXRT02- Small General Service	12,783.8600	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	4,333.4420	11,012.4900	13,286.3000	12,603.5700	14,826.9300
TXRT11- Municipal Pumping	6,264.0010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	12,147.1800	9,255.6660	4,568.3970	5,069.0670	5,270.0460
TXRT22- Irrigation	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	297.2704	313.2858	233.5843	144.5354	142.0477
TXRT24- General Service	76,342.0400	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	45,301.0800	69,334.9800	73,604.2000	71,041.3100	87,260.9100
TXRT31- Military	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	6,915.0813	5,300.5947	5,265.8579	3,562.6117
TXRT41- City & County	16,838.3800	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	16,552.6200	7,423.9480	4,633.7780	12,606.2800	20,542.0400
NMRT01- Residential	0.6262	0.5620	0.4695	0.5438	0.4174	0.4149	0.6281	0.4489	0.6312	0.7011	0.6456	0.7287
NMRT03- Small General Service	9,153.8830	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	6,221.6420	9,148.2040	9,879.7440	8,665.0430	10,017.1800
NMRT04- General Service	11,118.8100	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	7,110.8600	10,471.2700	11,495.8300	10,799.1000	12,231.5200
NMRT05- Irrigation	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	7,392.8310	17,300.9900	9,203.1530	5,026.0960	4,297.9290	4,162.6110
NMRT07- City & County	5,690.5600	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	4,178.2250	2,091.5330	1,495.3390	2,514.4990	5,767.1740
NMRT08- Pumping	1,370.5960	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2,658.0300	2,047.7950	1,684.8210	1,287.6260	1,546.4390

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Actual kWh Sales	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
TXRT01- Residential	191,183,348	119,890,210	137,180,057	170,715,808	143,033,851	120,322,295	118,484,154	132,935,468	208,188,395	278,582,943	270,292,157	230,652,669
TXRTWH- Water Heating	646,344	724,917	923,319	1,072,843	1,014,615	882,959	817,884	728,146	693,465	542,755	487,567	567,709
TXRT28- Area Lighting	2,420,024	2,513,783	2,703,205	2,665,234	2,309,563	2,337,825	2,075,620	1,968,953	1,820,138	1,935,670	2,072,687	2,176,161
TXRTVRE- Voluntary Renewable Energy	0	0	0	0	0	0	0	0	0	0	0	0
TXRT02- Small General Service	24,984,266	18,587,430	18,848,333	20,655,851	20,264,619	19,555,833	19,368,491	20,760,030	25,667,660	29,751,696	29,751,442	27,907,014
TXRT07- Outdoor Recreational	578,560	554,005	461,076	351,143	488,551	468,064	397,824	390,924	408,720	352,998	380,787	484,821
TXRT22- Irrigation	328,787	206,290	181,411	95,800	129,054	376,487	919,087	618,464	590,016	765,167	597,989	346,248
TXRT24- General Service	140,704,907	108,602,376	104,637,815	109,532,807	106,418,496	110,027,382	111,504,019	116,556,097	147,305,477	163,219,974	159,370,085	155,005,586
TXRT25- Large Power	54,807,710	55,579,197	48,323,005	47,255,236	49,914,628	46,125,954	52,699,089	49,081,704	58,341,896	60,227,672	63,652,138	61,591,941
TXRT25A- Large Power Off-Peak	82,941	92,697	103,646	103,570	102,192	114,500	120,689	118,340	121,342	118,235	146,392	134,060
TXRT34- Cotton Gin	9,210	360,789	515,877	569,347	88,780	16,726	14,388	6,678	7,356	5,963	5,726	8,164
TXRT15- Electrolytic Refining	3,944,680	5,568,484	3,866,817	4,942,512	5,728,476	4,910,193	4,961,061	4,999,246	5,030,926	4,005,943	3,600,864	4,222,196
TXRT26- Petroleum Refinery	24,932,079	27,342,287	25,701,141	30,521,166	28,298,772	25,647,787	28,238,457	26,132,388	28,758,824	37,171,485	28,754,829	29,883,973
TXRT30- Electric Furnace	1,540,123	2,050,001	1,561,037	1,191,202	1,717,183	1,432,772	1,336,150	1,634,278	1,738,143	1,645,213	1,441,869	1,141,484
TXRT38- Interruptible	31,200,827	29,260,671	23,972,198	23,565,383	27,847,776	22,876,932	25,648,597	28,552,327	38,636,018	32,667,440	38,399,978	32,629,953
TXRT08- Street Lighting	2,949,951	3,069,460	3,297,710	3,219,049	2,808,462	2,835,095	2,526,252	2,435,543	2,212,362	2,359,516	2,544,273	2,669,330
TXRT09- Traffic Signals	218,241	218,889	219,196	218,445	218,454	218,454	218,454	218,454	218,864	219,000	219,086	219,086
TXRT11- Water Pumping	3,625,544	2,938,578	3,136,589	2,140,035	1,776,908	1,338,044	2,053,321	2,601,726	2,416,125	1,640,874	1,442,508	1,603,271
TXRT11TU- TOU Water Pumping	10,823,648	9,218,143	11,204,941	9,271,224	12,054,024	14,140,801	9,784,982	8,909,427	11,483,783	12,327,910	11,724,060	11,445,361
TXRT31- Military	20,161,634	23,748,125	20,995,029	23,575,486	22,823,028	21,008,967	20,820,220	19,353,949	23,590,537	22,692,624	23,877,244	22,285,795
TXRT41- City & County	27,594,924	21,203,544	20,984,975	19,649,427	22,315,360	20,794,040	21,481,658	23,649,609	27,225,640	25,697,548	28,620,163	31,764,796
TXRT45- Cogen Supplemental	2,036,133	2,063,408	1,830,037	2,150,183	1,964,392	1,972,472	2,193,166	2,006,399	2,327,809	2,456,016	2,605,767	2,516,246
NMRT01- Residential	57,935,372	40,887,634	51,911,656	64,586,249	54,653,621	43,999,364	40,571,716	42,037,134	63,688,287	84,291,793	82,876,751	71,025,185
NMRT12- Area Lighting	412,421	414,611	417,136	417,662	418,183	413,126	414,528	414,892	415,375	415,423	415,097	416,502
NMRT33- Small System REC Purchase	0	0	0	0	0	0	0	0	0	0	0	0
NMRT34- Medium System REC Purchase	0	0	0	0	0	0	0	0	0	0	0	0
NMRT03- Small General Service	15,286,406	11,591,634	11,424,381	12,911,645	12,152,206	11,766,370	11,538,528	11,812,659	14,897,200	17,696,776	17,923,867	16,618,459
NMRT04- General Service	28,211,636	22,565,771	21,776,123	23,260,501	22,474,187	22,785,544	23,228,238	23,761,745	28,390,914	31,059,395	30,943,700	30,362,072
NMRT05- Irrigation	4,959,761	1,674,661	552,275	306,227	924,097	3,287,824	5,025,929	6,007,904	7,066,418	6,389,708	5,666,213	4,438,518
NMRT07- City & County	6,770,488	5,356,281	5,055,174	5,101,354	5,371,511	5,173,201	5,070,699	5,458,684	5,761,182	6,378,161	7,048,579	7,578,949
NMRT08- Pumping	3,034,693	2,353,451	1,942,233	2,205,111	2,145,717	2,386,822	2,477,266	2,510,855	3,147,337	3,464,030	3,353,070	3,091,477
NMRT09- Large Power	10,084,780	10,974,070	9,592,421	10,183,078	10,358,914	8,755,210	10,329,638	11,221,709	13,153,594	13,266,615	14,587,251	13,165,999
NMRT11- Street Lighting	260,166	260,166	260,166	260,166	260,166	260,137	258,944	261,488	261,488	261,488	261,488	261,146
NMRT19- Seasonal Agricultural	590,910	1,299,795	1,442,631	871,767	223,727	72,626	41,348	40,940	129,740	318,671	552,557	339,632
NMRT25- Outdoor Recreational	86,063	57,321	31,415	23,659	25,268	41,035	47,648	53,096	56,373	57,491	61,898	38,688
NMRT29- Interruptible	994,387	1,036,379	774,786	656,949	577,255	611,226	739,419	719,267	875,293	1,006,930	1,059,538	1,046,404
NMRT10- Military	12,437,334	12,365,400	11,484,885	12,711,956	13,302,288	11,233,372	11,955,614	9,395,363	12,489,188	16,756,469	11,879,222	12,671,061
NMRT26- State University	3,287,538	2,764,959	2,060,240	1,649,302	2,375,140	2,052,879	2,684,667	2,313,159	2,628,500	3,411,956	4,017,272	3,272,822

Number of Customers for UPC Models	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
TXRT01- Residential	274,205	274,443	274,556	275,172	275,389	275,942	276,319	276,912	277,431	277,518	277,946	277,904
NMRT01- Residential	84,026	84,078	84,093	84,210	84,289	84,463	84,565	84,679	84,673	84,723	84,894	84,984

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Description	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Test Year Total
Unadjusted kWh													
TXRT01- Residential	191,183,348	119,890,210	137,180,057	170,715,808	143,033,851	120,322,295	118,484,154	132,935,468	208,188,395	278,582,943	270,292,157	230,652,669	2,121,461,355
TXRTWH- Water Heating	646,344	724,917	923,319	1,072,843	1,014,615	882,959	817,884	728,146	693,465	542,755	487,567	567,709	9,102,523
TXRT28- Area Lighting	2,420,024	2,513,783	2,703,205	2,665,234	2,309,563	2,337,825	2,075,620	1,968,953	1,820,138	1,935,670	2,072,687	2,176,161	26,998,864
TXRTVRE- Voluntary Renewable Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT02- Small General Service	24,984,266	18,587,430	18,848,333	20,655,851	20,264,619	19,555,833	19,368,491	20,760,030	25,667,660	29,751,696	29,751,442	27,907,014	276,102,665
TXRT07- Outdoor Recreational	578,560	554,005	461,076	351,143	488,551	468,064	397,824	390,924	408,720	352,998	380,787	484,821	5,317,473
TXRT22- Irrigation	328,787	206,290	181,411	95,800	129,054	376,487	919,087	618,464	590,016	765,167	597,989	346,248	5,154,800
TXRT24- General Service	140,704,907	108,602,376	104,637,815	109,532,807	106,418,496	110,027,382	111,504,019	116,556,097	147,305,477	163,219,974	159,370,085	155,005,586	1,532,885,021
TXRT25- Large Power	54,807,710	55,579,197	48,323,005	47,255,236	49,914,628	46,125,954	52,699,089	49,081,704	58,341,896	60,227,672	63,652,138	61,591,941	647,600,170
TXRT25A- Large Power Off-Peak	82,941	92,697	103,646	103,570	102,192	114,500	120,689	118,340	121,342	118,235	146,392	134,060	1,358,604
TXRT34- Cotton Gin	9,210	360,789	515,877	569,347	88,780	16,726	14,388	6,678	7,356	5,963	5,726	8,164	1,609,004
TXRT15- Electrolytic Refining	3,944,680	5,568,484	3,866,817	4,942,512	5,728,476	4,910,193	4,961,061	4,999,246	5,030,926	4,005,943	3,600,864	4,222,196	55,781,398
TXRT26- Petroleum Refinery	24,932,079	27,342,287	25,701,441	30,521,166	28,298,772	25,647,787	28,238,457	26,132,388	28,758,824	37,171,485	28,754,829	29,883,973	341,383,488
TXRT30- Electric Furnace	1,540,123	2,050,001	1,561,037	1,191,202	1,717,183	1,432,772	1,336,150	1,634,278	1,738,143	1,645,213	1,441,869	1,141,484	18,429,455
TXRT38- Interruptible	31,200,827	29,260,671	23,972,198	23,565,383	27,847,776	22,876,932	25,648,597	28,552,327	38,636,018	32,667,440	38,399,978	32,629,953	355,258,100
TXRT08- Street Lighting	2,949,951	3,069,460	3,297,710	3,219,049	2,808,462	2,835,095	2,526,252	2,435,543	2,212,362	2,359,516	2,544,273	2,669,330	32,927,003
TXRT09- Traffic Signals	218,241	218,889	219,196	218,445	218,454	218,454	218,454	218,454	218,864	219,000	219,086	219,086	2,624,623
TXRT11- Water Pumping	3,625,544	2,938,578	3,136,589	2,140,035	1,776,908	1,338,044	2,053,321	2,601,726	2,416,125	1,640,874	1,442,508	1,603,271	26,713,523
TXRT11TU- TOU Water Pumping	10,823,648	9,218,143	11,204,941	9,271,224	12,054,024	14,140,801	9,784,982	8,909,427	11,483,783	12,327,910	11,724,060	11,445,361	132,388,304
TXRT31- Military	20,161,634	23,748,125	20,995,029	23,575,486	22,823,028	21,008,967	20,820,220	19,353,949	23,590,537	22,692,624	23,877,244	22,285,795	264,932,638
TXRT41- City & County	27,594,924	21,203,544	20,984,975	19,649,427	22,315,360	20,794,040	21,481,658	23,649,609	27,225,640	25,697,548	28,620,163	31,764,796	290,981,684
TXRT45- Cogen Supplemental	2,036,133	2,063,408	1,830,037	2,150,183	1,964,392	1,972,472	2,193,166	2,006,399	2,327,809	2,456,016	2,605,767	2,516,246	26,122,028
Total Unadjusted kWh	544,773,881	433,793,284	430,647,714	473,461,751	451,317,184	417,403,582	425,663,563	443,658,149	586,783,496	678,386,642	669,987,611	619,255,864	6,175,132,723

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Description	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Test Year Total
Weather Adjustments to kWh													
TXRT01- Residential	(12,901,345)	1,044,145	1,111,464	796,085	1,384,512	4,726,368	5,737,125	2,200,550	3,594,614	(11,728,216)	(6,955,338)	5,193,294	(5,796,741)
TXRTWH- Water Heating	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT28- Area Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRTVRE- Voluntary Renewable Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT02- Small General Service	(1,099,412)	0	0	0	0	0	0	151,670	297,337	(930,041)	(529,350)	415,154	(1,694,641)
TXRT07- Outdoor Recreational	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT22- Irrigation	0	0	0	0	0	0	0	10,404	8,459	(16,351)	(6,070)	3,977	419
TXRT24- General Service	(6,565,415)	0	0	0	0	0	0	1,585,538	1,872,044	(5,152,294)	(2,983,735)	2,443,305	(8,800,557)
TXRT25- Large Power	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT25A- Large Power Off-Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT34- Cotton Gin	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT15- Electrolytic Refining	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT26- Petroleum Refinery	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT30- Electric Furnace	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT38- Interruptible	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT08- Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT09- Traffic Signals	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT11- Water Pumping	(538,704)	0	0	0	0	0	0	425,151	249,903	(319,788)	(212,901)	147,561	(248,777)
TXRT11TU- TOU Water Pumping	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT31- Military	0	0	0	0	0	0	0	0	186,707	(371,042)	(221,166)	99,753	(305,747)
TXRT41- City & County	(1,448,101)	0	0	0	0	0	0	579,342	200,447	(324,364)	(529,464)	575,177	(946,963)
TXRT45- Cogen Supplemental	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Weather Adjustment	(22,552,977)	1,044,145	1,111,464	796,085	1,384,512	4,726,368	5,737,125	4,952,656	6,409,512	(18,842,096)	#########	8,878,223	(17,793,008)

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Description	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Test Year Total
Weather Adjusted kWh													
TXRT01- Residential	178,282,003	120,934,355	138,291,521	171,511,893	144,418,363	125,048,663	124,221,279	135,136,018	211,783,009	266,854,727	263,336,819	235,845,963	2,115,664,614
TXRTWH- Water Heating	646,344	724,917	923,319	1,072,843	1,014,615	882,959	817,884	728,146	693,465	542,755	487,567	567,709	9,102,523
TXRT28- Area Lighting	2,420,024	2,513,783	2,703,205	2,665,234	2,309,563	2,337,825	2,075,620	1,968,953	1,820,138	1,935,670	2,072,687	2,176,161	26,998,864
TXRTVRE- Voluntary Renewable Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
TXRT02- Small General Service	23,884,854	18,587,430	18,848,333	20,655,851	20,264,619	19,555,833	19,368,491	20,911,700	25,964,997	28,821,655	29,222,092	28,322,168	274,408,024
TXRT07- Outdoor Recreational	578,560	554,005	461,076	351,143	488,551	468,064	397,824	390,924	408,720	352,998	380,787	484,821	5,317,473
TXRT22- Irrigation	328,787	206,290	181,411	95,800	129,054	376,487	919,087	628,868	598,475	748,816	591,919	350,225	5,155,219
TXRT24- General Service	134,139,492	108,602,376	104,637,815	109,532,807	106,418,496	110,027,382	111,504,019	118,141,635	149,177,521	158,067,680	156,386,350	157,448,891	1,524,084,464
TXRT25- Large Power	54,807,710	55,579,197	48,323,005	47,255,236	49,914,628	46,125,954	52,699,089	49,081,704	58,341,896	60,227,672	63,652,138	61,591,941	647,600,170
TXRT25A- Large Power Off-Peak	82,941	92,697	103,646	103,570	102,192	114,500	120,689	118,340	121,342	118,235	146,392	134,060	1,358,604
TXRT34- Cotton Gin	9,210	360,789	515,877	569,347	88,780	16,726	14,388	6,678	7,356	5,963	5,726	8,164	1,609,004
TXRT15- Electrolytic Refining	3,944,680	5,568,484	3,866,817	4,942,512	5,728,476	4,910,193	4,961,061	4,999,246	5,030,926	4,005,943	3,600,864	4,222,196	55,781,398
TXRT26- Petroleum Refinery	24,932,079	27,342,287	25,701,441	30,521,166	28,298,772	25,647,787	28,238,457	26,132,388	28,758,824	37,171,485	28,754,829	29,883,973	341,383,488
TXRT30- Electric Furnace	1,540,123	2,050,001	1,561,037	1,191,202	1,717,183	1,432,772	1,336,150	1,634,278	1,738,143	1,645,213	1,441,869	1,141,484	18,429,455
TXRT38- Interruptible	31,200,827	29,260,671	23,972,198	23,565,383	27,847,776	22,876,932	25,648,597	28,552,327	38,636,018	32,667,440	38,399,978	32,629,953	355,258,100
TXRT08- Street Lighting	2,949,951	3,069,460	3,297,710	3,219,049	2,808,462	2,835,095	2,526,252	2,435,543	2,212,362	2,359,516	2,544,273	2,669,330	32,927,003
TXRT09- Traffic Signals	218,241	218,889	219,196	218,445	218,454	218,454	218,454	218,454	218,864	219,000	219,086	219,086	2,624,623
TXRT11- Water Pumping	3,086,840	2,938,578	3,136,589	2,140,035	1,776,908	1,338,044	2,053,321	3,026,877	2,666,028	1,321,086	1,229,607	1,750,832	26,464,746
TXRT11TU- TOU Water Pumping	10,823,648	9,218,143	11,204,941	9,271,224	12,054,024	14,140,801	9,784,982	8,909,427	11,483,783	12,327,910	11,724,060	11,445,361	132,388,304
TXRT31- Military	20,161,634	23,748,125	20,995,029	23,575,486	22,823,028	21,008,967	20,820,220	19,353,949	23,777,244	22,321,582	23,656,078	22,385,548	264,626,891
TXRT41- City & County	26,146,823	21,203,544	20,984,975	19,649,427	22,315,360	20,794,040	21,481,658	24,228,951	27,426,087	25,373,184	28,090,699	32,339,973	290,034,721
TXRT45- Cogen Supplemental	2,036,133	2,063,408	1,830,037	2,150,183	1,964,392	1,972,472	2,193,166	2,006,399	2,327,809	2,456,016	2,605,767	2,516,246	26,122,028
Total Weather Adjusted kWh	522,220,904	434,837,429	431,759,178	474,257,836	452,701,696	422,129,951	431,400,688	448,610,806	593,193,007	659,544,547	658,549,587	628,134,087	6,157,339,715

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Description	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Test Year Total
Unadjusted kWh													
NMRT01- Residential	57,935,372	40,887,634	51,911,656	64,586,249	54,653,621	43,999,364	40,571,716	42,037,134	63,688,287	84,291,793	82,876,751	71,025,185	698,464,762
NMRT12- Area Lighting	412,421	414,611	417,136	417,662	418,183	413,126	414,528	414,892	415,375	415,423	415,097	416,502	4,984,956
NMRT33- Small System REC Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT34- Medium System REC Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT03- Small General Service	15,286,406	11,591,634	11,424,381	12,911,645	12,152,206	11,766,370	11,538,528	11,812,659	14,897,200	17,696,776	17,923,867	16,618,459	165,620,131
NMRT04- General Service	28,211,636	22,565,771	21,776,123	23,260,501	22,474,187	22,785,544	23,228,238	23,761,745	28,390,914	31,059,395	30,943,700	30,362,072	308,819,826
NMRT05- Irrigation	4,959,761	1,674,661	552,275	306,227	924,097	3,287,824	5,025,929	6,007,904	7,066,418	6,389,708	5,666,213	4,438,518	46,299,535
NMRT07- City & County	6,770,488	5,356,281	5,055,174	5,101,354	5,371,511	5,173,201	5,070,699	5,458,684	5,761,182	6,378,161	7,048,579	7,578,949	70,124,263
NMRT08- Pumping	3,034,693	2,353,451	1,942,233	2,205,111	2,145,717	2,386,822	2,477,266	2,510,855	3,147,337	3,464,030	3,353,070	3,091,477	32,112,062
NMRT09- Large Power	10,084,780	10,974,070	9,592,421	10,183,078	10,358,914	8,755,210	10,329,638	11,221,709	13,153,594	13,266,615	14,587,251	13,165,999	135,673,279
NMRT11- Street Lighting	260,166	260,166	260,166	260,166	260,166	260,137	258,944	261,488	261,488	261,488	261,488	261,146	3,127,009
NMRT19- Seasonal Agricultural	590,910	1,299,795	1,442,631	871,767	223,727	72,626	41,348	40,940	129,740	318,671	552,557	339,632	5,924,344
NMRT25- Outdoor Recreational	86,063	57,321	31,415	23,659	25,268	41,035	47,648	53,096	56,373	57,491	61,898	38,688	579,955
NMRT29- Interruptible	994,387	1,036,379	774,786	656,949	577,255	611,226	739,419	719,267	875,293	1,006,930	1,059,538	1,046,404	10,097,833
NMRT10- Military	12,437,334	12,365,400	11,484,885	12,711,956	13,302,288	11,233,372	11,955,614	9,395,363	12,489,188	16,756,469	11,879,222	12,671,061	148,682,152
NMRT26- State University	3,287,538	2,764,959	2,060,240	1,649,302	2,375,140	2,052,879	2,684,667	2,313,159	2,628,500	3,411,956	4,017,272	3,272,822	32,518,434
Total Unadjusted kWh	144,351,955	113,602,133	118,725,522	135,145,626	125,262,280	112,838,736	114,384,182	116,008,895	152,960,889	184,774,906	180,646,503	164,326,914	1,663,028,541

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Description	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Test Year Total
Weather Adjustments to kWh													
NMRT01- Residential	(3,735,723)	614,276	(789,579)	(1,465,394)	457,370	2,663,533	1,487,230	646,268	(267,237)	(4,574,039)	(1,918,196)	928,902	(5,952,590)
NMRT12- Area Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT33- Small System REC Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT34- Medium System REC Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT03- Small General Service	(649,926)	0	0	0	0	0	0	105,768	(45,741)	(760,740)	(303,277)	150,258	(1,503,658)
NMRT04- General Service	(789,436)	0	0	0	0	0	0	120,885	(52,356)	(885,179)	(377,969)	183,473	(1,800,582)
NMRT05- Irrigation	0	0	0	0	0	0	206,999	294,117	(46,016)	(387,009)	(150,428)	62,439	(19,897)
NMRT07- City & County	(404,030)	0	0	0	0	0	0	71,030	(10,458)	(115,141)	(88,007)	86,508	(460,099)
NMRT08- Pumping	(97,312)	0	0	0	0	0	0	45,187	(10,239)	(129,731)	(45,067)	23,197	(213,966)
NMRT09- Large Power	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT11- Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT19- Seasonal Agricultural	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT25- Outdoor Recreational	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT29- Interruptible	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT10- Military	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT26- State University	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Weather Adjustment	(5,676,427)	614,276	(789,579)	(1,465,394)	457,370	2,663,533	1,694,229	1,283,254	(432,047)	(6,851,840)	(2,882,943)	1,434,776	(9,950,792)

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Description	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Test Year Total
Weather Adjusted kWh													
NMRT01- Residential	54,199,649	41,501,910	51,122,077	63,120,855	55,110,991	46,662,897	42,058,946	42,683,402	63,421,050	79,717,754	80,958,555	71,954,087	692,512,172
NMRT12- Area Lighting	412,421	414,611	417,136	417,662	418,183	413,126	414,528	414,892	415,375	415,423	415,097	416,502	4,984,956
NMRT33- Small System REC Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT34- Medium System REC Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
NMRT03- Small General Service	14,636,480	11,591,634	11,424,381	12,911,645	12,152,206	11,766,370	11,538,528	11,918,427	14,851,459	16,936,036	17,620,590	16,768,717	164,116,473
NMRT04- General Service	27,422,200	22,565,771	21,776,123	23,260,501	22,474,187	22,785,544	23,228,238	23,882,630	28,338,558	30,174,216	30,565,732	30,545,545	307,019,244
NMRT05- Irrigation	4,959,761	1,674,661	552,275	306,227	924,097	3,287,824	5,232,928	6,302,021	7,020,402	6,002,699	5,515,785	4,500,957	46,279,638
NMRT07- City & County	6,366,458	5,356,281	5,055,174	5,101,354	5,371,511	5,173,201	5,070,699	5,529,714	5,750,724	6,263,020	6,960,572	7,665,457	69,664,164
NMRT08- Pumping	2,937,381	2,353,451	1,942,233	2,205,111	2,145,717	2,386,822	2,477,266	2,556,042	3,137,098	3,334,299	3,308,003	3,114,674	31,898,096
NMRT09- Large Power	10,084,780	10,974,070	9,592,421	10,183,078	10,358,914	8,755,210	10,329,638	11,221,709	13,153,594	13,266,615	14,587,251	13,165,999	135,673,279
NMRT11- Street Lighting	260,166	260,166	260,166	260,166	260,166	260,137	258,944	261,488	261,488	261,488	261,488	261,146	3,127,009
NMRT19- Seasonal Agricultural	590,910	1,299,795	1,442,631	871,767	223,727	72,626	41,348	40,940	129,740	318,671	552,557	339,632	5,924,344
NMRT25- Outdoor Recreational	86,063	57,321	31,415	23,659	25,268	41,035	47,648	53,096	56,373	57,491	61,898	38,688	579,955
NMRT29- Interruptible	994,387	1,036,379	774,786	656,949	577,255	611,226	739,419	719,267	875,293	1,006,930	1,059,538	1,046,404	10,097,833
NMRT10- Military	12,437,334	12,365,400	11,484,885	12,711,956	13,302,288	11,233,372	11,955,614	9,395,363	12,489,188	16,756,469	11,879,222	12,671,061	148,682,152
NMRT26- State University	3,287,538	2,764,959	2,060,240	1,649,302	2,375,140	2,052,879	2,684,667	2,313,159	2,628,500	3,411,956	4,017,272	3,272,822	32,518,434
Total Weather Adjusted kWh	138,675,528	114,216,409	117,935,943	133,680,232	125,719,650	115,502,269	116,078,411	117,292,149	152,528,842	177,923,066	177,763,560	165,761,690	1,653,077,749

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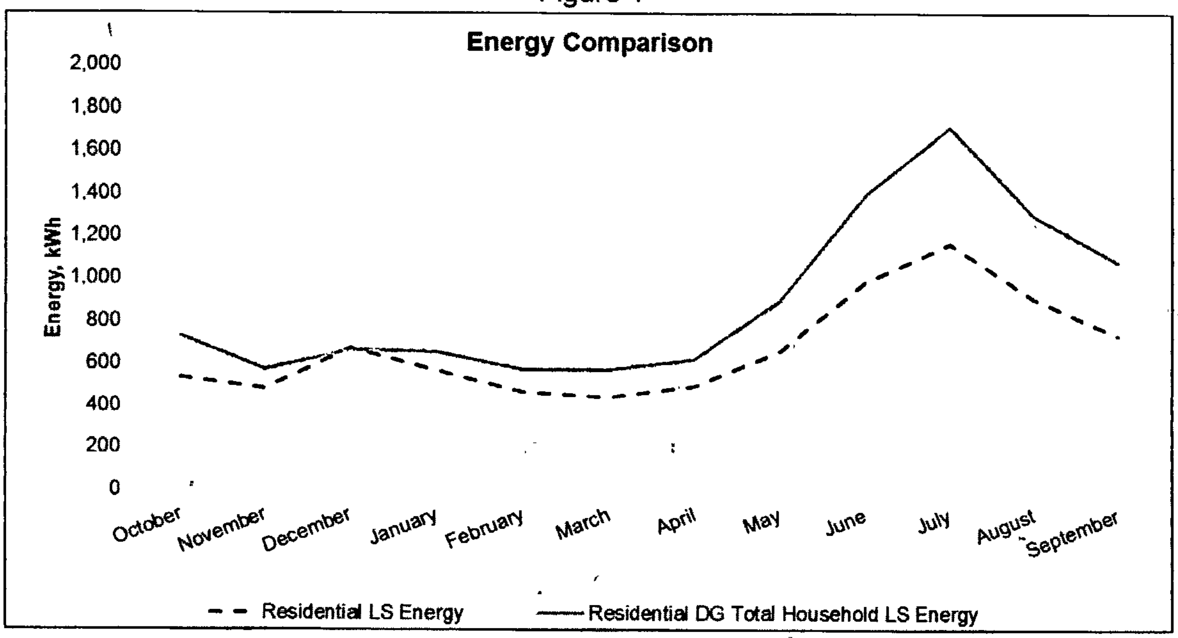
Exhibit GN-6 Historical Load

Year	Native Peak Demand	Native System Energy
2005	1,376	7,334,819
2006	1,428	7,481,256
2007	1,508	7,694,664
2008	1,524	7,669,160
2009	1,571	7,707,261
2010	1,616	8,046,019
2011	1,711	8,342,116
2012	1,688	8,399,958
2013	1,750	8,354,189
2014	1,766	8,230,271
2015	1,794	8,441,421
10 Year CAGR	2.7	1.4

Comparing Load Characteristics of Residential Customers to Residential Distributed Generation Customers

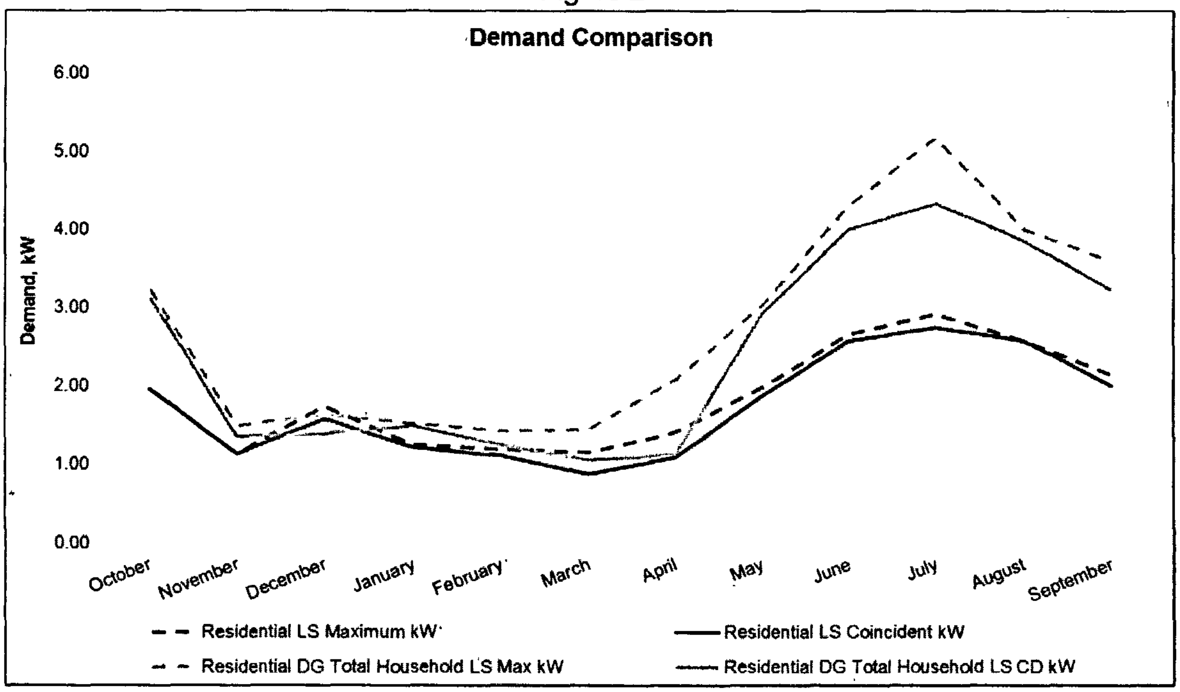
- The Economic Research Department designs sample load studies to determine load characteristics for large rate classes. With over 270,000 customers, a load study sample is used to model load patterns for the Texas residential class. Texas residential customers consumed an average of 677 kWh monthly during the year ending September 30, 2016. This is comparable to the average residential sales reported in the 2015 10-K. The 10-K reports an annual average consumption of 7,763 kWh or 647 kWh average monthly sales per customer.
- Load patterns for residential distributed generation (DG) customers are modeled in the same manner as the Texas residential class. For the year ending September 2016, the residential DG sample consisted of 57 customers. As estimated by the Texas residential DG load study, residential customers with DG consumed an average of 899 kWh monthly for the test year, supplied through a combination of EPE system resources and self-generation. On average, residential DG customers consume approximately 32.77% more energy than the typical residential customer (shown in the graph below).
- As shown in Figure 1 below, this difference between residential DG customers and residential customers is more pronounced in the four coincident peak (CP) summer months (June – September) where a typical residential customer consumed an average of 949 kWh and a residential DG customer consumed 1,372 kWh monthly, or approximately 44.54% more.

Figure 1



- The same pattern can be seen in Figure 2 below, when comparing average coincident and maximum demand for these customers. "Coincident" demand refers to demand measured at the time of the EPE monthly system peak, where "maximum" refers to the customers peak demand regardless of when it occurs.
- The average residential DG customer's load is 49.17% and 40.42% higher than a typical residential customer for maximum kW and coincident kW, respectively. During the 4CP months, as with energy consumption, a residential DG customer's load is significantly higher than the load for the average residential customer, approximately 66.12% for maximum kW, and 55.59% for coincident kW.

Figure 2

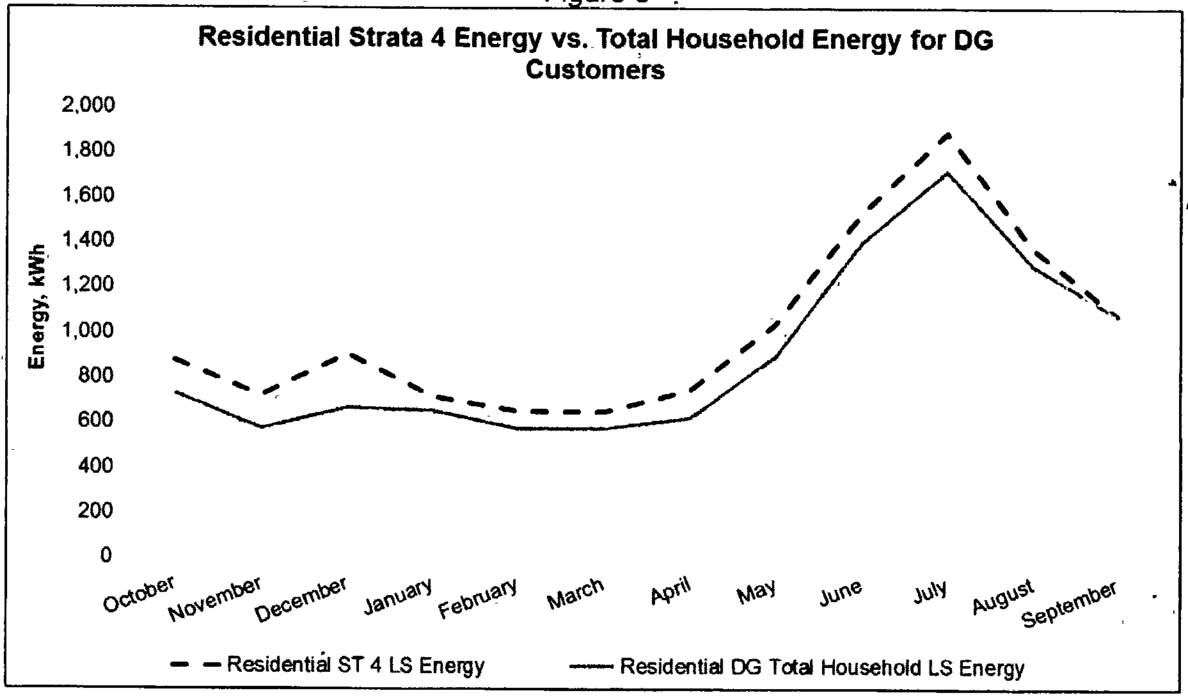


Residential DG Customers are Typically High Usage Customers

- On average, residential DG customers consume more energy than the typical residential customer. Therefore, it would be more practical to analyze this class in comparison to customers that have similar usage patterns.
- The Texas Residential load study is stratified by energy and consists of five strata. The strata boundaries are listed below.
  - Strata 1: 0 – 300 kWh
  - Strata 2: 301 – 500 kWh
  - Strata 3: 501 – 800 kWh
  - Strata 4: 801 – 1,400 kWh
  - Strata 5: 1,401 – 19,000 kWh

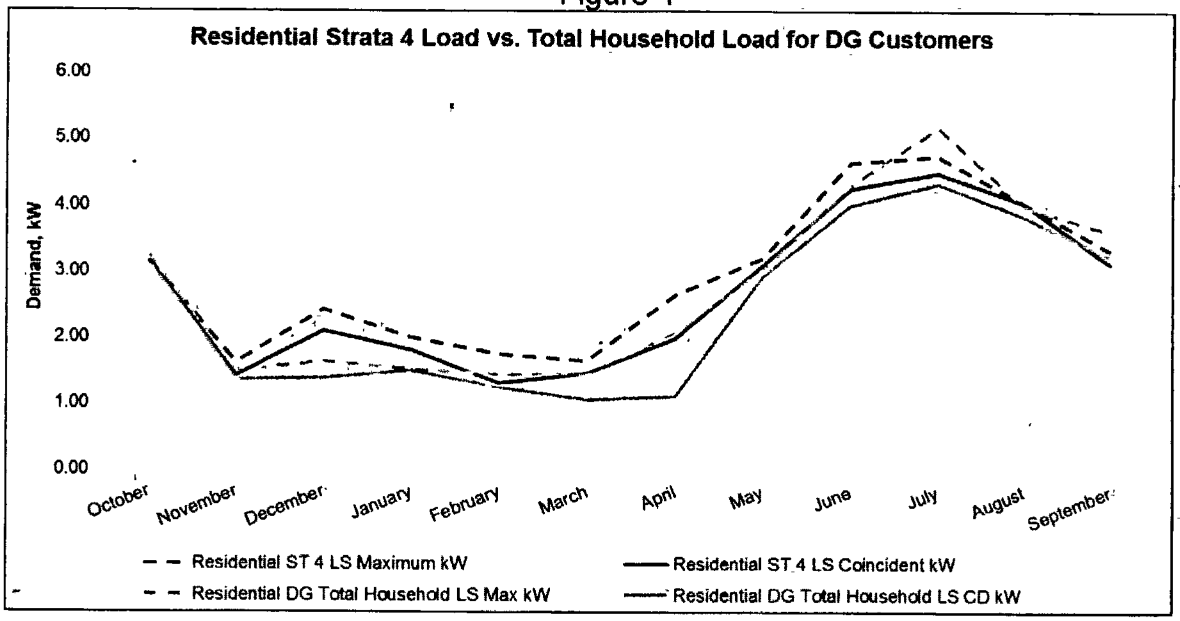
- With an average annual consumption of 899 kWh monthly, residential DG customers are most comparable to the high usage customers that fall in strata 4. Figure 3 below show the similarity between the residential DG customers and the strata 4 residential customers.
- The energy consumption between the two types of customers is almost identical.

Figure 3



- The same observation can be made for demand patterns between a residential DG customer's total household load and a high usage strata 4 customer in Figure 4 below.

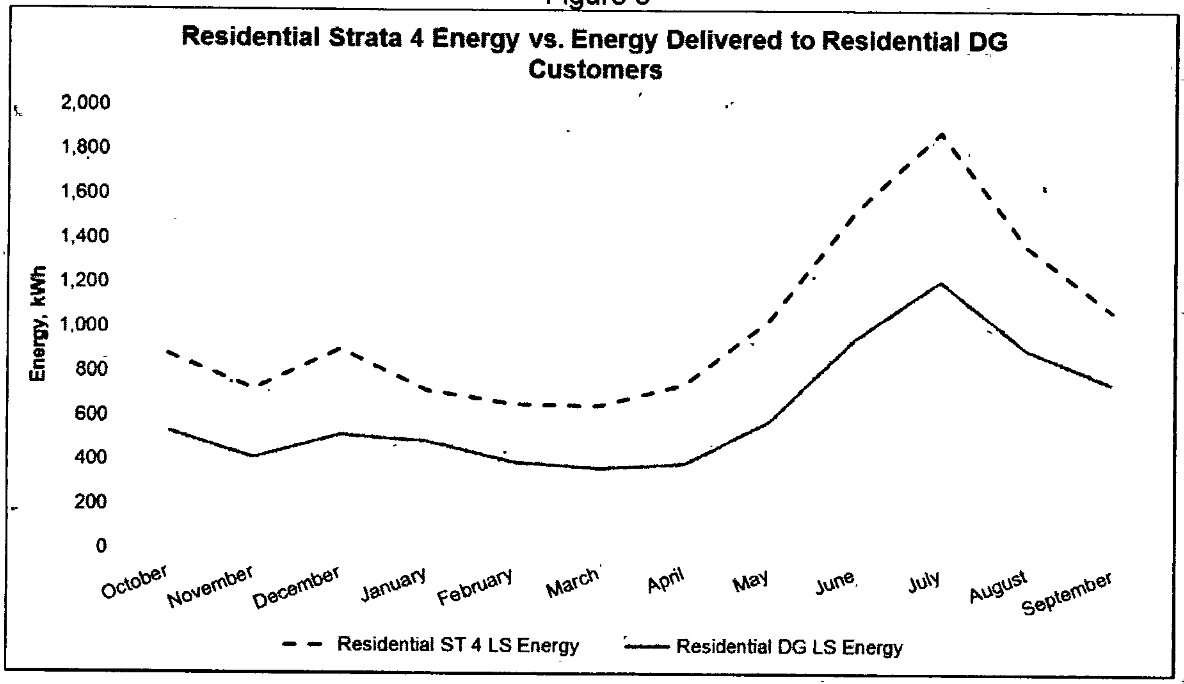
Figure 4



Energy Consumption for Residential DG Customers

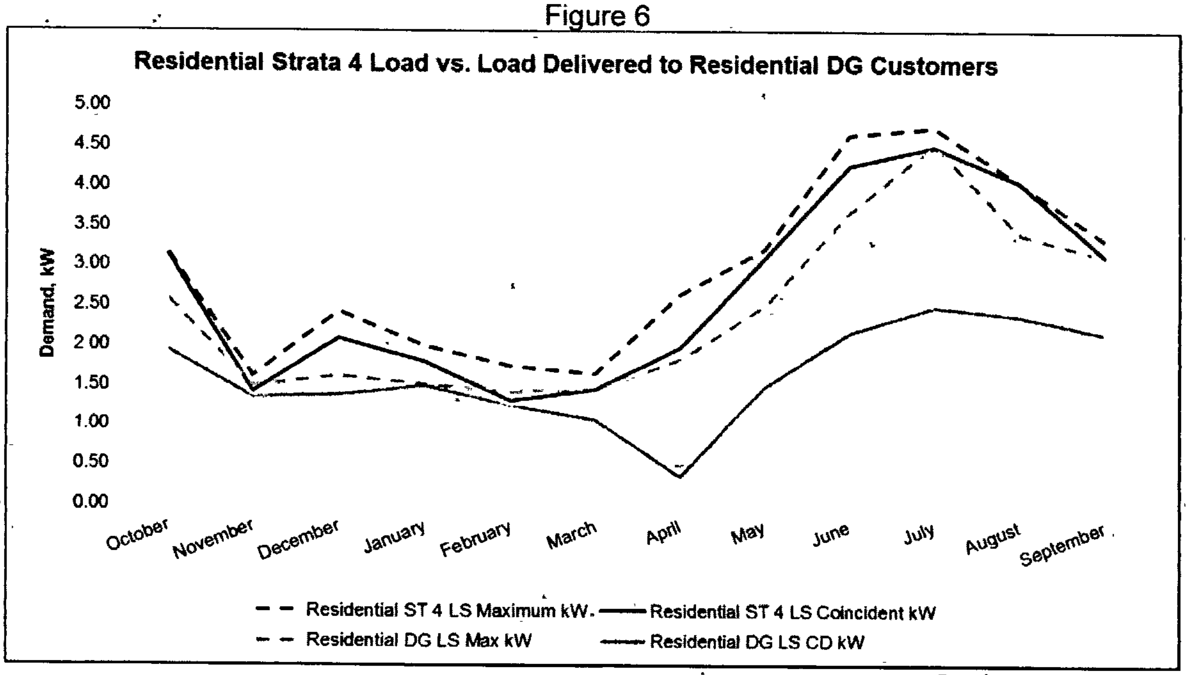
- Despite the similarities of a residential DG customer's total household consumption to the high usage customers that fall in the Texas strata 4 load study, these customers' solar panel production partially offsets the amount of energy provided to them by El Paso Electric, creating a markedly different retail service profile.
- A residential strata 4 customer consumed an average of 1,015 kWh monthly during the test year, while EPE supplied residential DG customers an average of 626 kWh monthly, or 38.34% less. This difference can be seen in Figure 5 below.

Figure 5



- Figure 6 below, illustrates how a customer's load requirements change when considering only the load delivered to residential DG customers as opposed to their total household consumption. The load for both maximum demand and coincident demand follow the expected patterns.

Figure 6

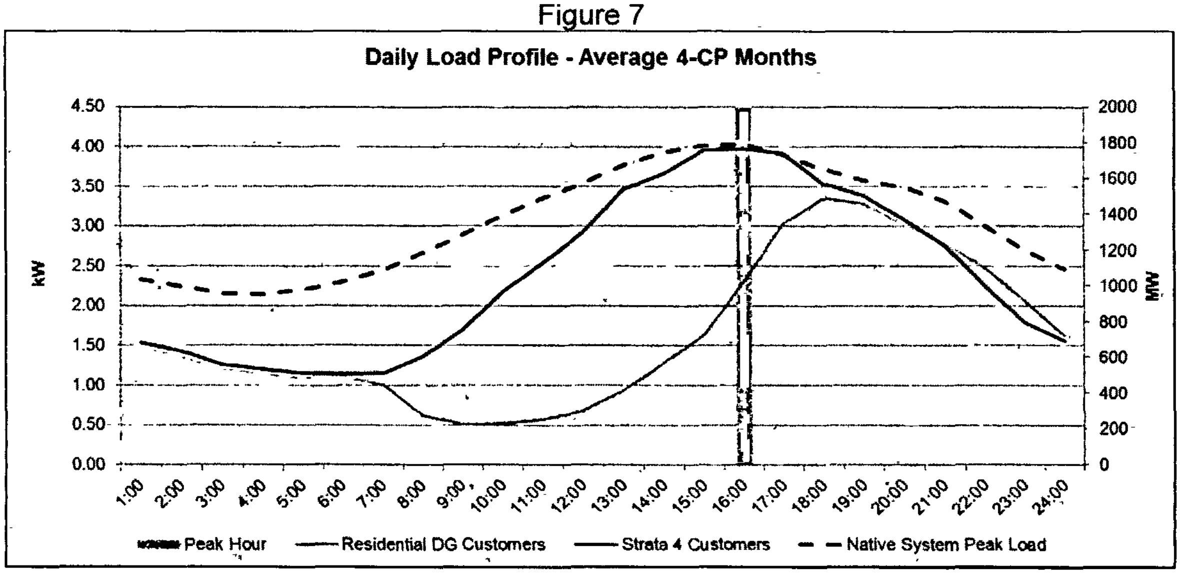


- A typical residential customer's peak demand (Maximum Diversified Demand) occurs in the late afternoon hours. The same is true for residential DG customers, whose maximum demand occurs in the late evening when not much sunlight is available to displace their load. As a result, the maximum demand for a residential DG customer is not distinctly different than that of a residential strata 4 customer with no solar panels.
- During the 4CP months, the monthly EPE native system peak occurred at 16:00 MST from June through September. The graph depicts a decrease in load requirements for the residential DG customers during these months. During this time, the load delivered to the residential DG customers was 42.33% lower than the residential customers in strata 4. Residential DG customers contribute less on average to the EPE system peak demand during the 4CP summer months.
- During the winter months, where the native peak occurred at 20:00 MST, the coincident demand for a residential DG customer does not significantly differ from a regular strata 4 residential customer's coincident demand. During these months, residential DG customers contribute to the EPE system peak in roughly the same proportion as do strata 4 customers.

Hourly Interval Load During Peak Periods

- Figure 7 below, compares the hourly delivered load profile for residential DG customers to the hourly delivered load profile of residential customers in Strata 4 during the 4 CP months of June–September of 2016.

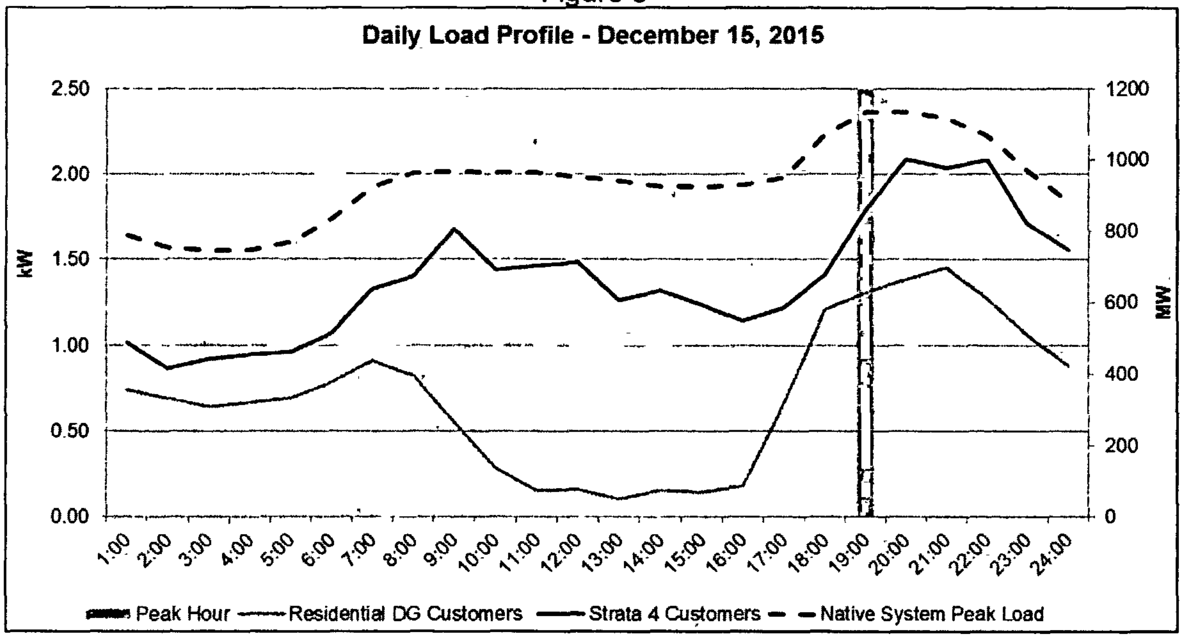
Figure 7



- During daylight hours, the load provided to residential DG customers by EPE is greatly reduced by the customer's solar generation.
- The load patterns during a winter peak day are similar. Figure 8, below, compares the hourly delivered load profile for residential DG customers to the hourly delivered load profile of residential customers in Strata 4 during the peak day in December 2015.

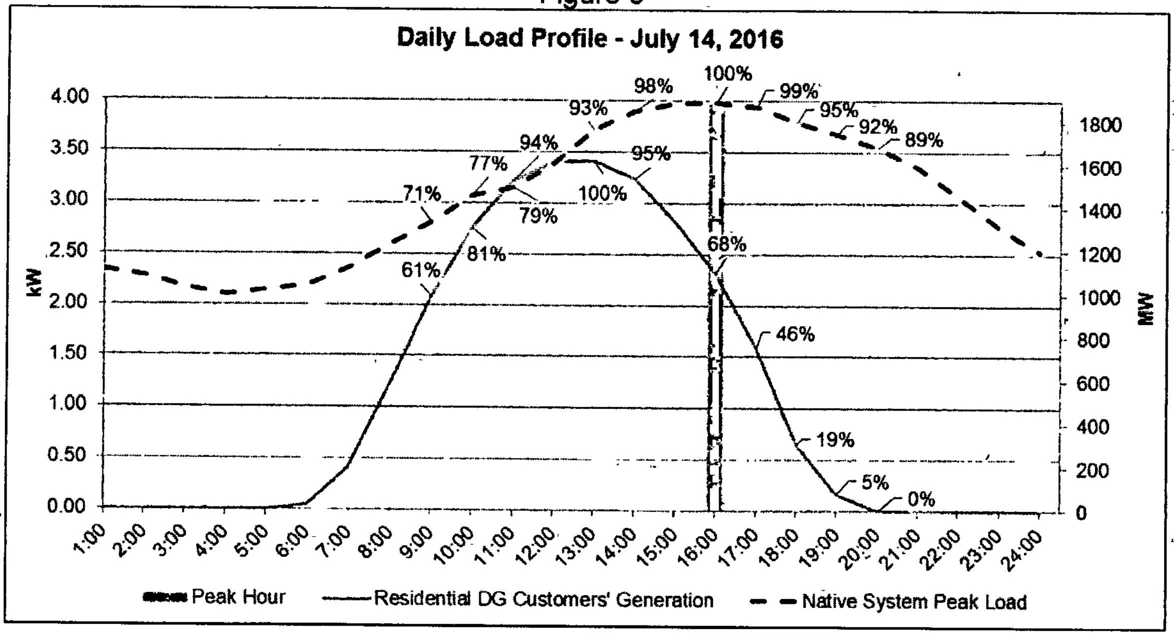
- The residential DG customers load is partially offset by the solar panel's production during the daylight hours. However, given that the peak during a winter month occurs during night time, the difference in usage between both customers is reduced.

Figure 8



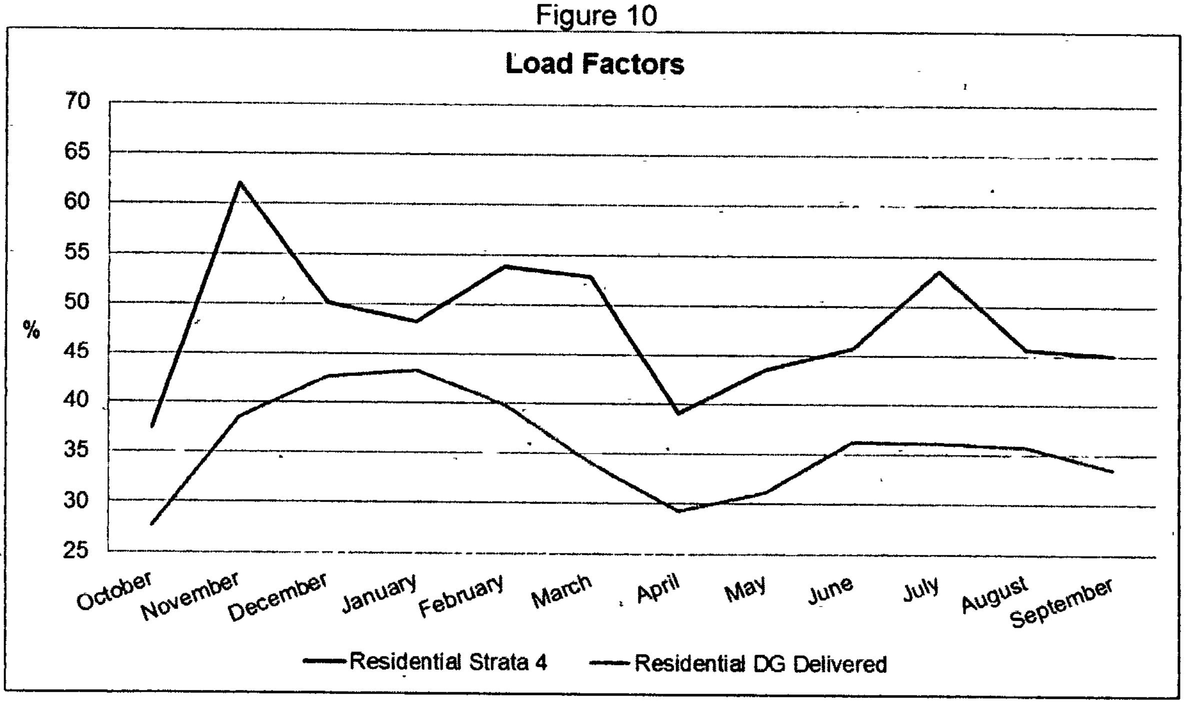
- Figure 9, below, isolates the average DG system's generation profile and compares it to EPE's hourly native system peak profile for the native system peak day on July 14, 2016.The load patterns during a winter peak day are similar.
- As you can see from Figure 9, the average DG system production drops significantly after it reaches its maximum output at 13:00 hours. However, EPE must serve the drop in the output of the DG systems while the native system peak demand remains at high levels for several hours.

Figure 9



- The daily consumption patterns of residential DG customers are more volatile than residential customers due to their ramp up of energy consumption in the late afternoon to early evening hours.
- The volatility in residential DG customers' delivered load profile is highlighted by their monthly load factors shown in Figure 10.

Figure 10



Load Characteristics Analysis of Texas Rate 41 Sampled Customers

Summary

Texas Rate 41 is composed of municipal and county governmental agencies as well as public schools. This is an existing rate that is closed to new customers. While the rate was open to new customers, the only criterion for being placed on this rate was for customers to belong to a public school district or a municipal/county government agency. Customers did not have to meet any energy consumption or peak demand conditions to qualify for the rate. As a result, customers in Rate 41 have usage characteristics that are very different from each other. This study compares the usage characteristics of the various customers included in Texas Rate 41 and the usage characteristics of customers under existing El Paso Electric (EPE) rate classes, i.e., Small General Service, General Service, and Large Power Service. This study finds that customers currently under Texas Rate 41, depending on their usage, can be classified under one of the three aforementioned pre-existing EPE rates because they meet the tariff criteria necessary to receive service under these rates. In addition, the usage patterns of current Texas Rate 41 customers are similar to the usage patterns of customers already in the other existing rates.

This study also shows that the energy consumption patterns of public schools are similar to EPE's non-school customers (existing sampled Rate 41 customers that are not identified as a building used as a school) for a majority of the year. However, the consumption patterns of public schools for various peak demand measures were more volatile than EPE's non-school customers and therefore are not highly correlated with each other.

Introduction

Texas Rate 41 is composed of city and county governmental entities and public school districts in El Paso Electric's Texas service area. This rate has been closed to new customers since 2010. While the rate was still open, the only requirement to be placed on this rate was for customers to belong to a public school district or a municipal/county government agency. At the current time, new public school facilities and municipal/county government entities are placed into the corresponding existing EPE tariff depending on the type of consumption that they expect to have, such as Small General Service, General Service, and Large Power Service. The minimum energy and/or demand criteria for each rate are specified in each tariff. Assigning customers to rates in this manner ensures that there is homogeneity within each rate class and that costs of service are properly allocated.

This study analyzes the usage characteristics of customers in the Texas Rate 41 load research sample study and compares them to the sample study of the rate for which they would qualify if they were not in Rate 41. This study also compares the usage profiles of schools and non-schools, where non-schools are comprised of existing sampled Rate 41 customers that are not identified as a building used as a school.

Methodology

The analysis in this paper was conducted using load research data for the period of October 2015 to September 2016. Customers in TX Rate 41 were compared to customers in the Small General Service (TX Rate 02), General Service (TX Rate 24), and Large Power (TX Rate 25) rates. Customers in TX Rate 41 were separated into three groups: TX Rate 02 Equivalents, TX Rate 24 Equivalents, and TX Rate 25 Equivalents. Non-coincident demand data for the customers in the TX Rate 41 sample study and the tariffs for Texas rates 02, 24, and 25 were used to determine in which of these three groups they belong. Table 1 shows how the sampled customers were distributed.

Table 1: TX Rate 41 Distribution into Equivalent Rates

	TX Rate 02 Equivalents	TX Rate 24 Equivalents	TX Rate 25 Equivalents
TX Rate 41 with Interval Meters	21	155	21

The usage characteristics of customers in the TX Rate 02 Equivalents, TX Rate 24 Equivalents, and TX Rate 25 Equivalents groups were then compared to the usage characteristics of customers in the TX Rate 02, TX Rate 24, and TX Rate 25 load research studies, respectively. The sample studies for TX Rate 02 and TX Rate 24 are stratified random samples. The TX Rate 02 sample study is stratified based on energy; while the TX Rate 24 sample study is stratified based on non-coincident demand. Since the estimates obtained from the TX Rate 02 Equivalents and TX Rate 24 Equivalents groups are not stratified, i.e. simple averages are calculated for each load research measure, a comparison between the Equivalents groups and the rate class sample studies at the total class level is not appropriate. A comparison with a single stratum within the TX Rate 02 and the TX Rate 24 sample studies is preferred.

The 12-month average energy for customers in the TX Rate 02 Equivalents group was calculated and compared against the strata boundaries for the TX Rate 02 sample study. Because the 12-month average energy for the TX Rate 02 Equivalents group of 1,344 kWh falls within the boundaries of Stratum 3 of the TX Rate 02 sample study (1,001 to 2,000 kWh), customers in this stratum were chosen as the group for comparison with the TX Rate 02 Equivalents group.

Similarly, the 12-month average non-coincident demand for customers in the TX Rate 24 Equivalents group was calculated and compared against the strata boundaries for the TX Rate 24 sample study. Since the 12-month average non-coincident demand for the TX Rate 24 Equivalents group of 209 kW falls within the boundaries of Stratum 3 of the TX Rate 24 sample study (81 to 220 kW), customers in this stratum were chosen as the group for comparison with the TX Rate 24 Equivalents group. Because the TX Rate 25 study is a census study, a direct comparison with the TX Rate 25 Equivalents group can be made.

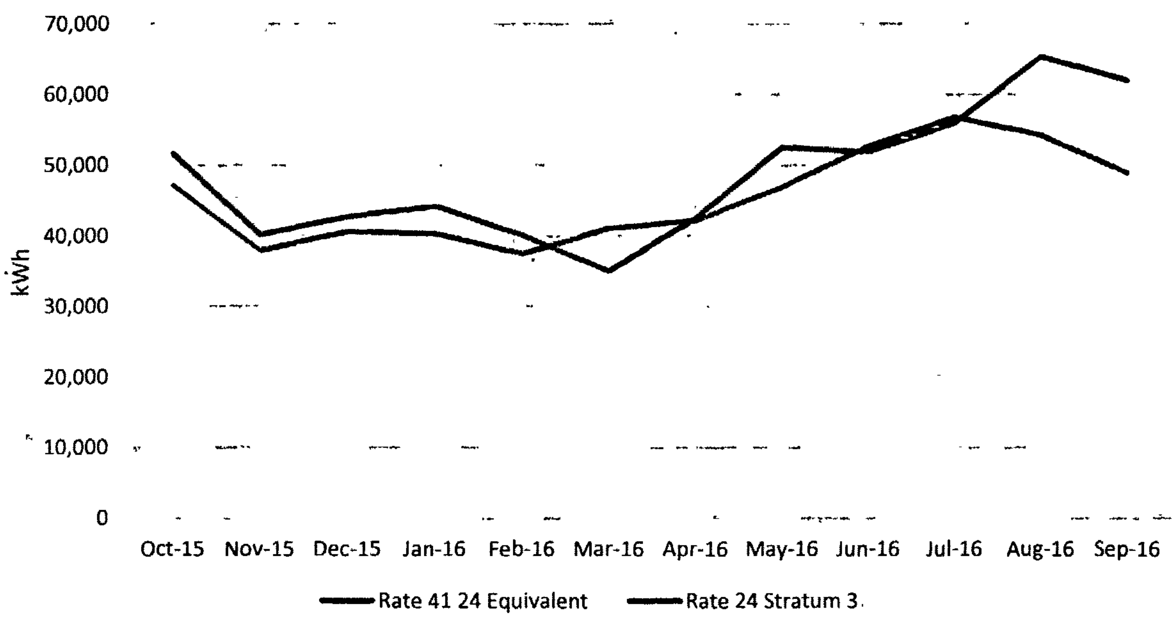
Results & Analysis

The results of this analysis are divided into six sections pertaining to the usage characteristics mentioned above.

I. Energy

Figure A-1, shown below, demonstrates how closely the monthly energy profiles of TX Rate 24 Stratum 3 and the TX Rate 24 Equivalents group move together, which suggests a similar usage behavior. The monthly energy values are very close to each other and move in nearly the same direction.

Figure A-1: Rate 24 Stratum 3 and Rate 24 Equivalent Monthly Energy



See Figures A-2 and A-3 in Appendix A for similar graphs relating to the energy profiles of TX Rate 02 Stratum 3 and TX Rate 25 compared to their counterparts in Rate 41. The Rate 02 Stratum 3 and Rate 02 Equivalents group also show very similar energy usage behavior. Although they move in opposite directions for several months, the monthly energy graphs, shown in Figure A-3, for TX Rate 25 and the Rate 25 equivalents in Rate 41, follow the same overall shape. TX Rate 25 is composed of customers with a minimum monthly demand of 600 kW and no upward limit. Given the broad range of customers that are billed under TX Rate 25, the significant difference in the average energy values between TX Rate 25 and the TX Rate 25 Equivalents observed in Figure A-3 is not surprising. Nonetheless, the similar pattern in energy usage from month to month suggests a resemblance between both groups.

Table 2, below, shows the correlation coefficient between each of the groups compared in Figures 1 through 4. The correlation coefficient measures the degree to which the movements of two variables are related. A value of -1 indicates a perfect negative correlation and a value of 1 indicates a perfect positive correlation.

Table 2: Energy Correlation Coefficients

	Correlation Coefficient
Rate 02 Stratum 3 and Rate 02 Equivalents	0.907
Rate 24 Stratum 3 and Rate 24 Equivalents	0.846
Rate 25 and Rate 25 Equivalents	-0.088

The correlation coefficients in Table 2 help to further illustrate how closely the energy profiles of customers in TX Rate 41 follow those of the otherwise applicable rates. The correlation coefficients between the Rate 02 Stratum 3 and Rate 24 Stratum 3 groups and their Rate 41 Equivalents are positive and close to 1, indicating a strong positive correlation. The Rate 25 and Rate 25 Equivalents correlation coefficient is very low, but given the wide range of customers that can qualify for this rate, we expect this sort of volatility.

II. Coincident Demand

Figures B-1, below, and Figures B-2 and B-3 in Appendix B show monthly coincident demand for the TX Rate 24 Stratum 3 sample study, TX Rate 02 Stratum 3 sample study, TX Rate 25 census study and their equivalents in TX Rate 41, respectively. All three graphs show that despite a few months in which the movements do not seem to mirror each other very well, the overall shape of the curves are very similar. This shows that at the time of the system peak, the demand from customers in the TX Rate 41 sample study behaves in a manner similar to customers in the rates in which they would be billed in the absence of TX Rate 41. In other words, although the coincident demand of each of these groups we are comparing is not necessarily the same, it increases and decreases during roughly the same months, indicating that the consumption behavior of customers in Rate 41 is similar to the consumption behavior of each pre-existing rate they are being compared to.

Figure B-1: Rate 24 Stratum 3 Sample Study and Rate 24 Equivalent Monthly Coincident Demand

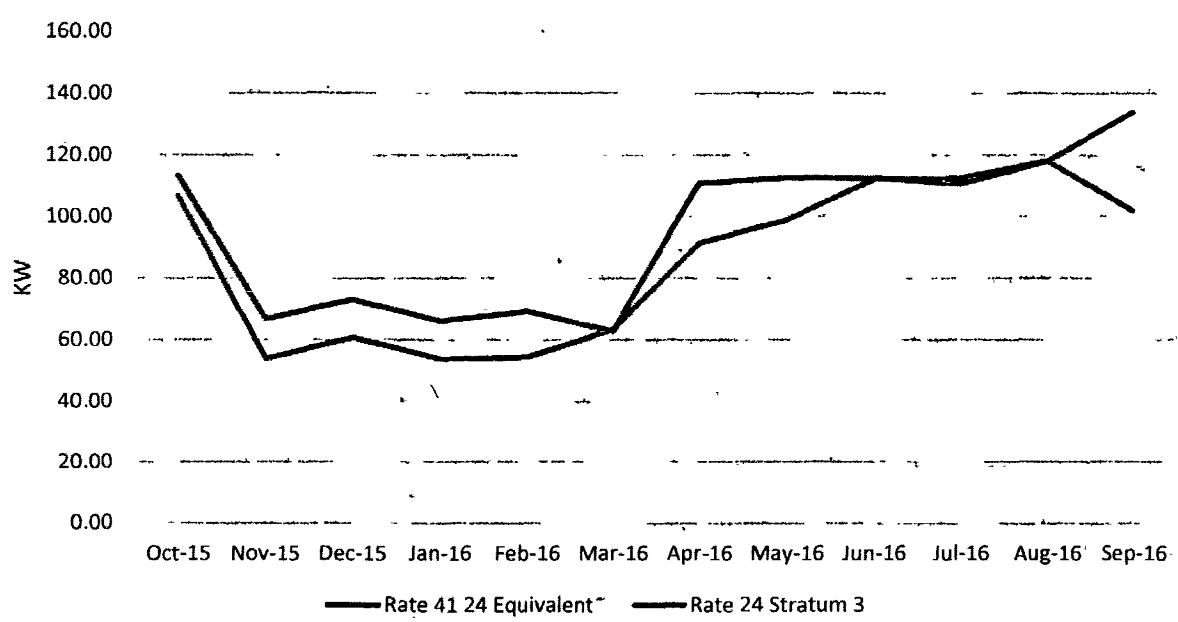


Table 3, below, shows the correlation coefficient between each of the groups compared in Figures B-1 through B-3.

Table 3: Coincident Demand Correlation Coefficients

	Correlation Coefficient
Rate 02 Stratum 3 and Rate 02 Equivalents	0.925
Rate 24 Stratum 3 and Rate 24 Equivalents	0.926
Rate 25 and Rate 25 Equivalents	0.697

These correlation coefficients show a strong linear relationship between the TX Rates 02, 24, and 25 studies and the TX Rate 41 equivalents. Although the coincident demand for the Rate 02 Stratum 3 customers shown in Figure 5 increases at a faster rate during the summer months than the Rate 02 Equivalent group, the correlation coefficient in Table 3 indicates that the curves move in the same direction 93% of the time.

III. Maximum Diversified Demand

Figure C-1, below, and Figures C-2 and C-3 in Appendix C show monthly maximum diversified demand (MDD) for the TX Rate 24 Stratum 3 sample study, TX Rate 02 Stratum 3 sample study, TX Rate 25 census study and their equivalents in TX Rate 41, respectively.

Figure C-1: Rate 24 Stratum 3 and Rate 24 Equivalents Monthly MDD

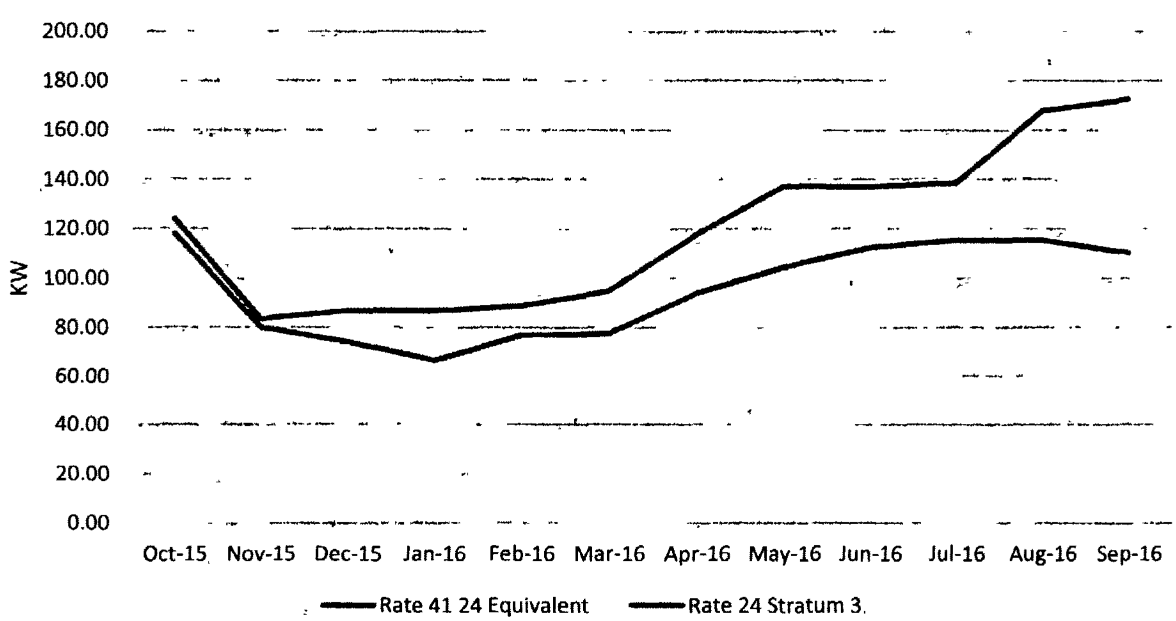


Figure C-1 shows that the monthly MDD curves for the TX Rate 24 Stratum 3 study and the TX Rate 24 Equivalents group are similar. Beginning in April, the MDD for the Rate 24 Equivalents group increases at a faster pace than that of the Rate 24 Stratum 3 group, but they still maintain an overall similar profile. Figure C-2 also illustrates a comparable shape between the TX Rate 02 Stratum 3 and the TX Rate 02 Equivalents monthly MDD curves. Figure C-3 shows very similar behavior to that observed in Figure C-2, with the monthly MDD for the TX Rate 25 and Rate 25 Equivalents groups very close to each other between the months of October through March and the Rate 25 group growing at a faster rate beginning in April. This provides more evidence to suggest that customers in the TX Rate 02 Equivalents, TX Rate 24 Equivalents, and TX Rate 25 Equivalents consume electricity in a similar manner to those in TX Rate 02, TX Rate 24, and TX Rate 25, respectively.

Table 4, below, shows the correlation coefficients for monthly MDD between each of the rate studied and their equivalents in TX Rate 41.

Table 4: Maximum Diversified Demand Correlation Coefficients

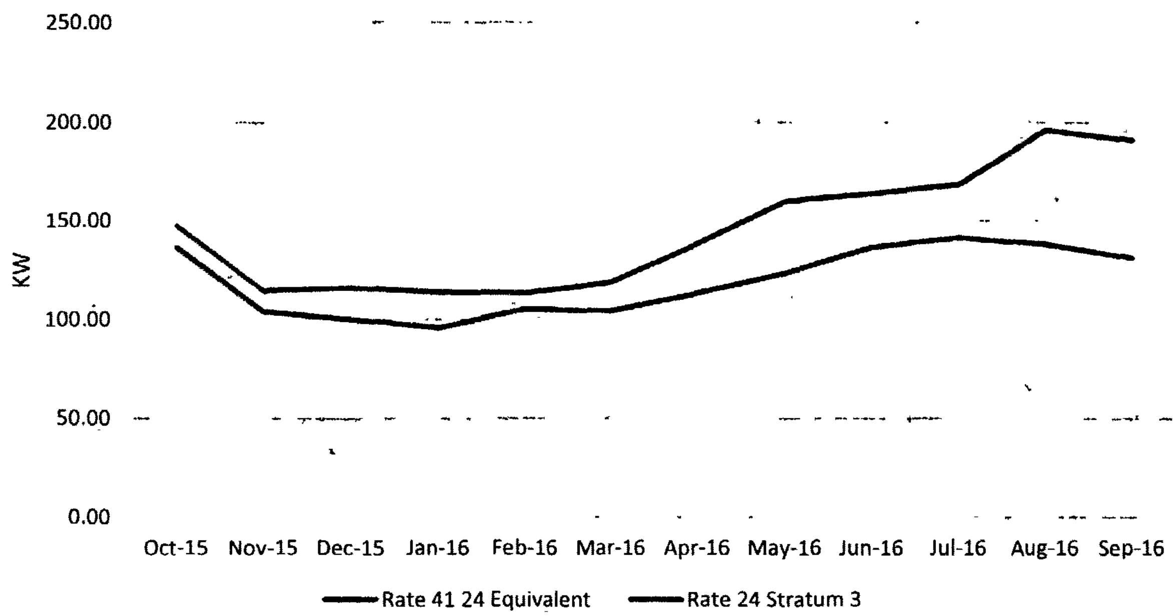
	Correlation Coefficient
Rate 02 Stratum 3 and Rate 02 Equivalents	0.901
Rate 24 Stratum 3 and Rate 24 Equivalents	0.874
Rate 25 and Rate 25 Equivalents	0.387

Table 4 demonstrates that MDD between each comparison group moves in a very similar direction despite isolated monthly variations. The behavior of MDD of customers in the TX Rate 41 sample study, therefore, is very similar to that of their otherwise applicable rates. Again, the weaker correlation observed with the TX Rate 25 groups is expected due to the wide range of customers that comprise TX Rate 25.

IV. Non-Coincident Demand

Figure D-1, shown below, and Figures D-2 and D-3 in Appendix D show that monthly non-coincident demand (NCD) curves for the TX Rate 24 Stratum 3 sample study, TX Rate 02 Stratum 3 sample study, TX Rate 25 census study and their equivalents in TX Rate 41 have a very similar shape. This indicates similar consumption behaviors and supports the proposition that customers in Rate 41 should be placed in the rates for which they would qualify based on the criteria outlined in each tariff.

Figure D-1: Rate 24 Stratum 3 and Rate 24 Equivalents Monthly NCD



The correlation coefficients between the TX Rate 02 Stratum 3, TX Rate 24 Stratum 3, and TX Rate 25 groups and their TX Rate 41 counterparts, shown in Table 5 below, denote a strong similarity in the movements of the comparable groups. Although they move in opposite directions for several months, the monthly NCD graphs, shown in Figure D-3, for TX Rate 25 and the Rate 25 equivalents in Rate 41, follow the same overall shape. TX Rate 25 is composed of customers with a minimum monthly demand of 600 kW and no upward limit. Given the broad range of customers that are billed under TX Rate 25, the difference in the average non-coincident demand values between TX Rate 25 and the TX Rate 25 Equivalents observed in Figure D-3 is not surprising.

Table 5: Non-Coincident Demand Correlation Coefficients

	Correlation Coefficient
Rate 02 Stratum 3 and Rate 02 Equivalents	0.887
Rate 24 Stratum 3 and Rate 24 Equivalents	0.883
Rate 25 and Rate 25 Equivalents	0.394

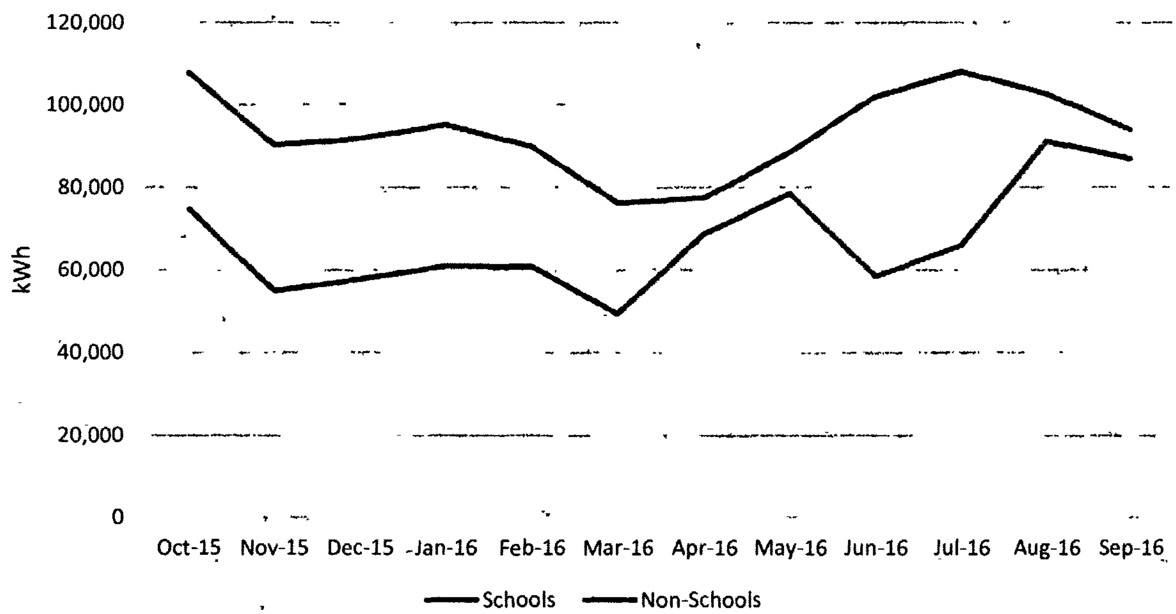
School Analysis

In addition to analysis above, EPE compared the usage profiles of schools and non-school customers, where non-schools are comprised of existing sampled Rate 41 customers that are not identified as a building used as a school.

The usage characteristics analyzed in this study are total energy, coincident demand, maximum diversified demand and non-coincident demand.

Figure E-1, below, compares average monthly energy between the Schools group of Rate 41 customers and the Non-Schools group.

Figure E-1: Schools and Non-Schools Monthly Energy



Energy for the Schools group dips during the months of June and July, when classes are out for at least part of each month in every school district. Energy for the Schools groups ramps up during the month of August when classes go back into session for most school districts. A slight decrease in consumption is observed in September, which mirrors a decrease in consumption in the Non-Schools group as well. Although a noticeable dip can be seen during the summer months in the Schools group when compared to the Non-Schools group, this decrease does not occur for all four critical-peak summer months. In fact, since 2010, four out of the seven native system peaks for EPE have occurred in the month of August, when consumption for Schools begins to rapidly increase as schools go back in session.

Figure E-2 in Appendix E shows that coincident demand for the Non-Schools group is relatively more flat and stable than that of the Schools group. Coincident demand for the Schools group is more peakish and increases during the critical-peak months of August and September.

Figure E-3 in Appendix E shows a more stable MDD for the Non-Schools group than the Schools group. MDD during the months of August and September actually increases for Schools, while it decreases for Non-Schools.

This contrasting pattern can also be observed between the monthly NCD of the Schools group and the Non-Schools group, shown in Figure E-4 of Appendix E. Although they follow each other closely during the months of October through February, the shape of both curves diverges in the following months. Table 6 provides the correlation coefficients for the monthly energy, coincident demand, MDD, and NCD data between the Schools and Non-Schools groups.

Table 6: Schools vs. Non-Schools Correlation Coefficients

	Correlation Coefficient
Energy	0.364
Coincident Demand	0.440
Maximum Diversified Demand	0.225
Non-Coincident Demand	0.013

Conclusions

The analysis presented in this paper suggests that the existing customers in TX Rate 41 have usage profiles that are similar to the usage profiles of customers in other existing rates for which they would qualify in the absence of TX Rate 41. The energy and various demand measures observed in this report show very clear similarities in the patterns of the TX Rate 02 Stratum 3, TX Rate 24 Stratum 3, and TX Rate 25 profiles with those of their TX Rate 41 equivalents. Although TX Rate 25 and the Rate 25 equivalents in Rate 41 follow the same overall shape, they do tend to have lower correlation coefficients than the other groups we compare. Given the broad range of customers that are billed under TX Rate 25, the difference in the average energy and demand values between TX Rate 25 and the TX Rate 25 Equivalents is not surprising.

In the case of the Schools and Non-Schools groups, there appears to be contrasting findings. In terms of energy, the Schools and Non-Schools groups exhibit similar usage patterns for the majority of the year, with the exception of June and July, when classes may not be in session for at least part of the month, if not the entire month. The consumption for Schools increases rapidly in the month of August as classes go back in session, at the same time as consumption for the Non-Schools group begins to taper off. In terms of demand, the Schools and Non-Schools groups exhibit dissimilar usage patterns for the majority of the year. Further analysis, including the creation of a load study specifically designed for schools, would enhance this study and may yield more conclusive results.

Appendix A – Energy Graphs

Figure A-2: Rate 02 Stratum 3 and Rate 02 Equivalent Monthly Energy

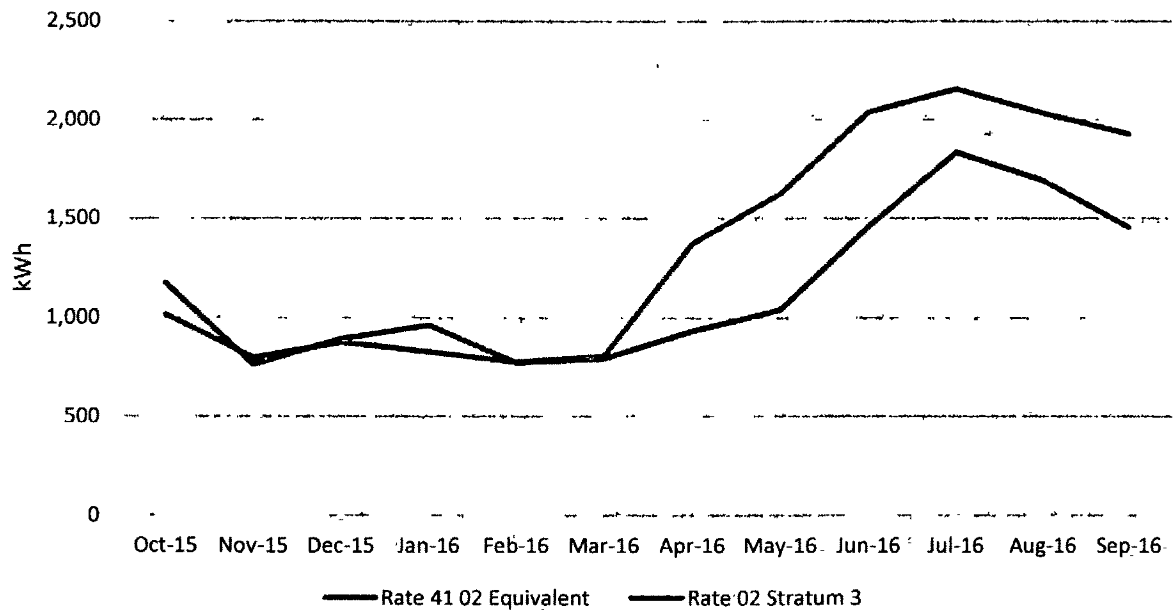
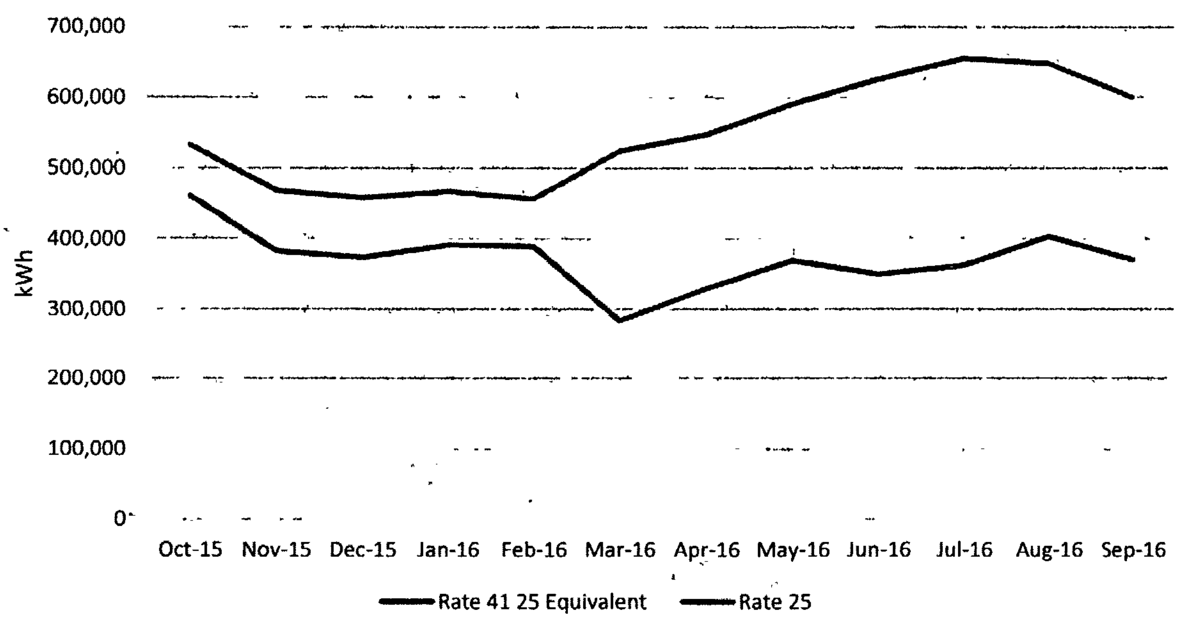


Figure A-3: Rate 25 Census Study and Rate 25 Equivalent Monthly Energy



Appendix B – Coincident Demand Graphs

Figure B-2: Rate 02 Stratum 3 Sample Study and Rate 02 Equivalent Monthly Coincident Demand

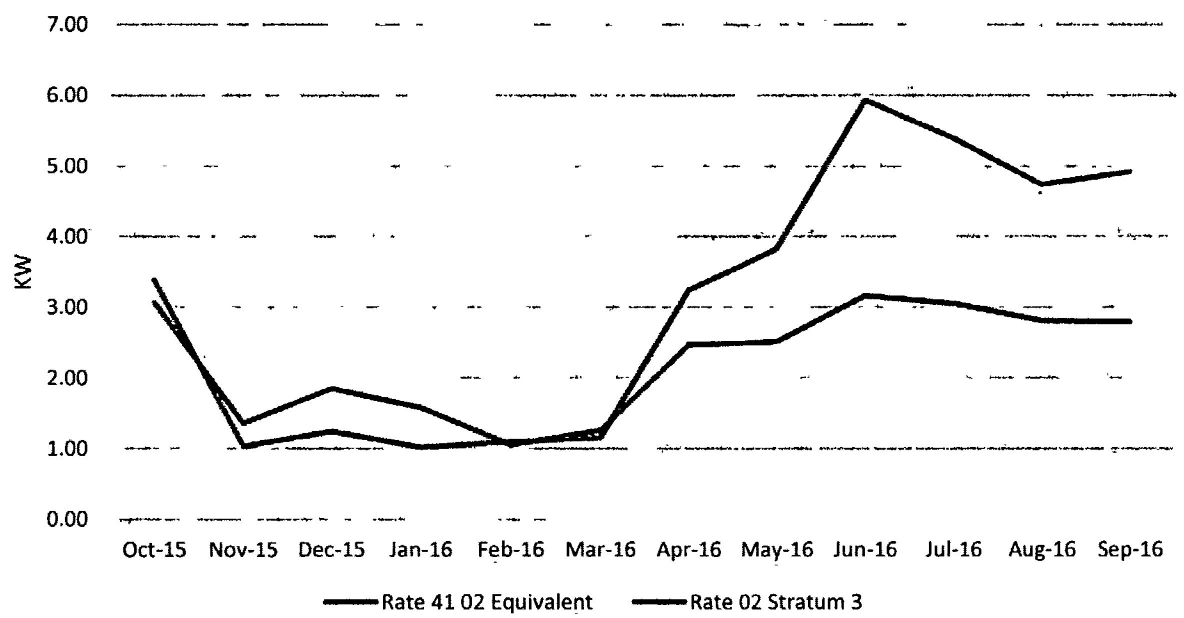
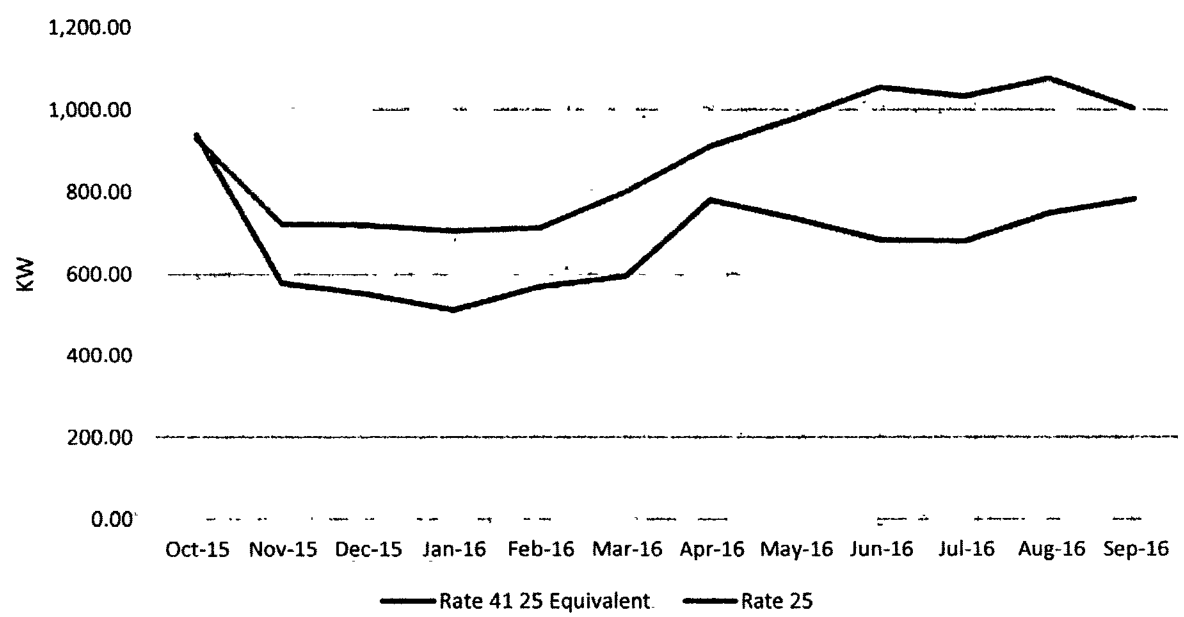


Figure B-3: Rate 25 Census Study and Rate 25 Equivalent Monthly Coincident Demand



Appendix C – Maximum Diversified Demand Graphs

Figure C-2: Rate 02 Stratum 3 and Rate 02 Equivalents Monthly MDD

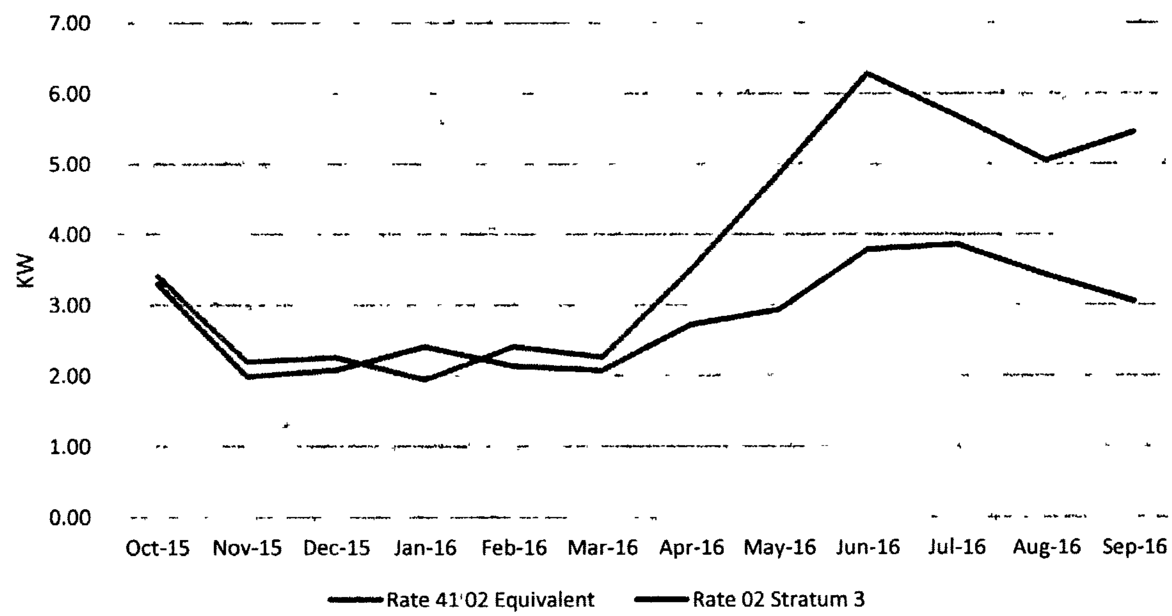
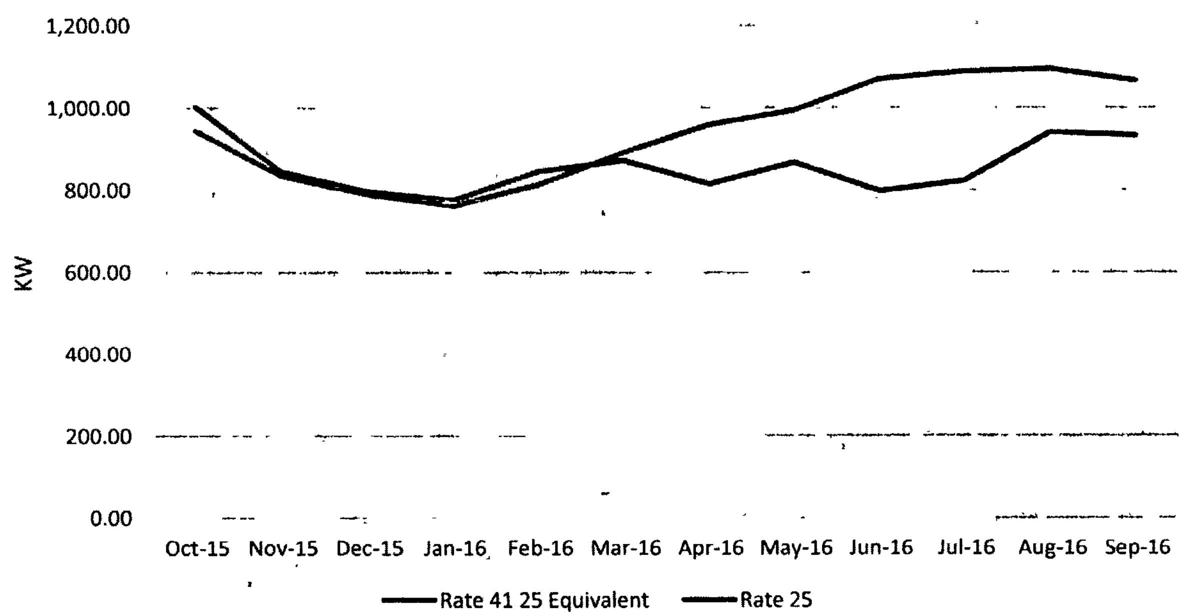


Figure C-3: Rate 25 Census Study and Rate 25 Equivalents Monthly MDD



Appendix D – Non-coincident Demand Graphs

Figure D-2: Rate 02 Stratum 3 and Rate 02 Equivalents Monthly NCD

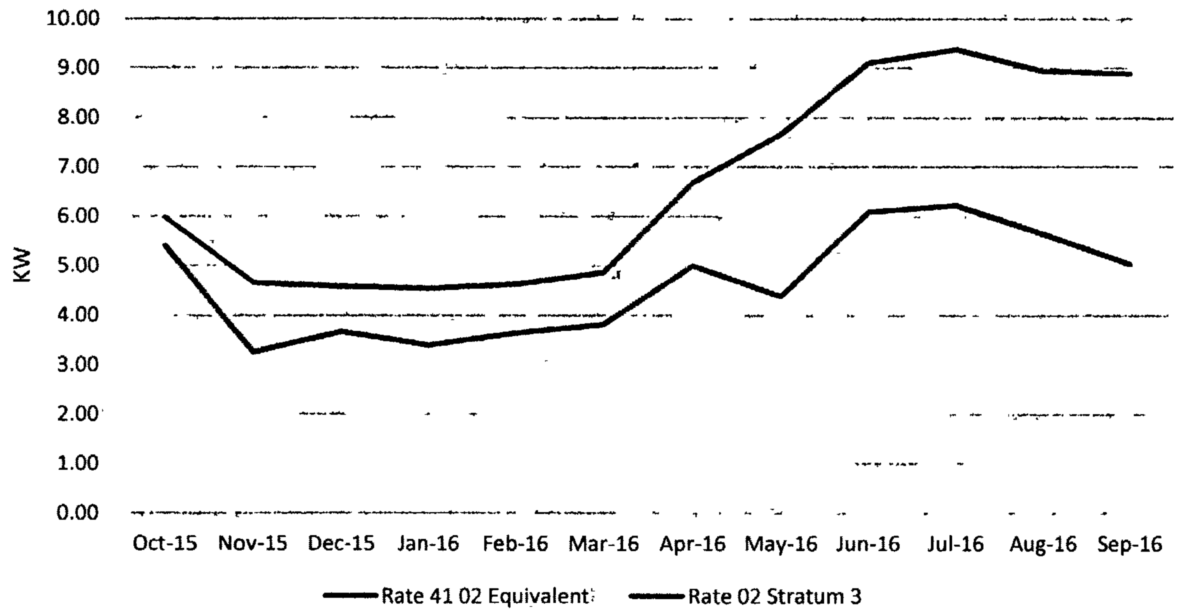
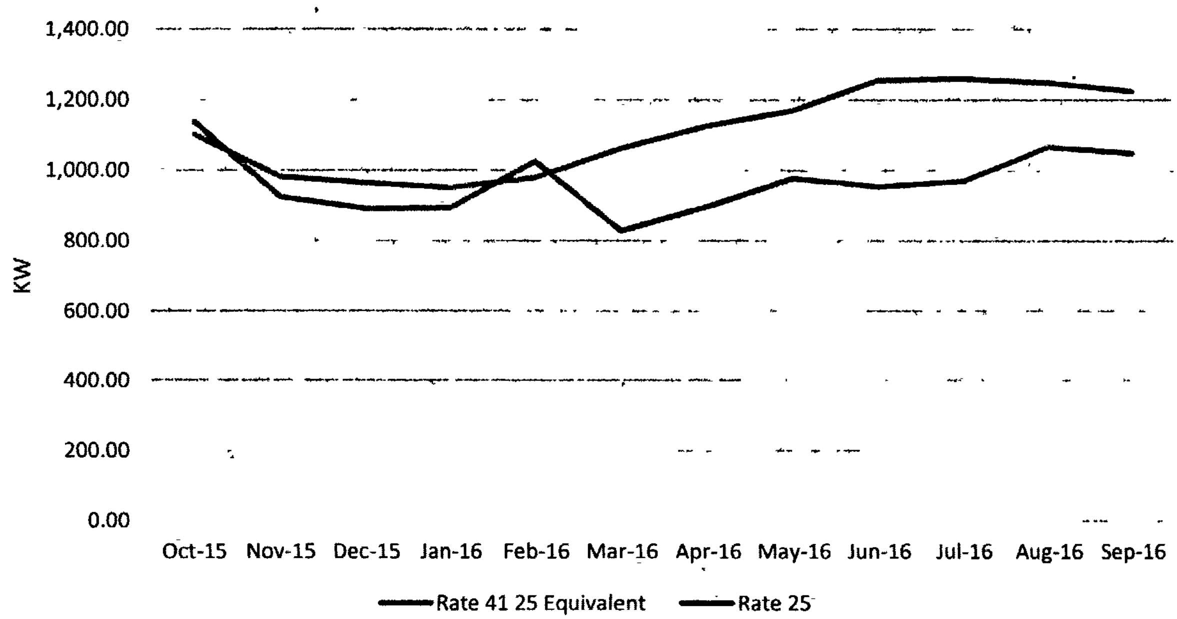


Figure D-3: Rate 25 Census Study and Rate 25 Equivalents Monthly NCD



Appendix E – Schools vs. Non-Schools Graphs

Figure E-2: Schools and Non-Schools Monthly Coincident Demand

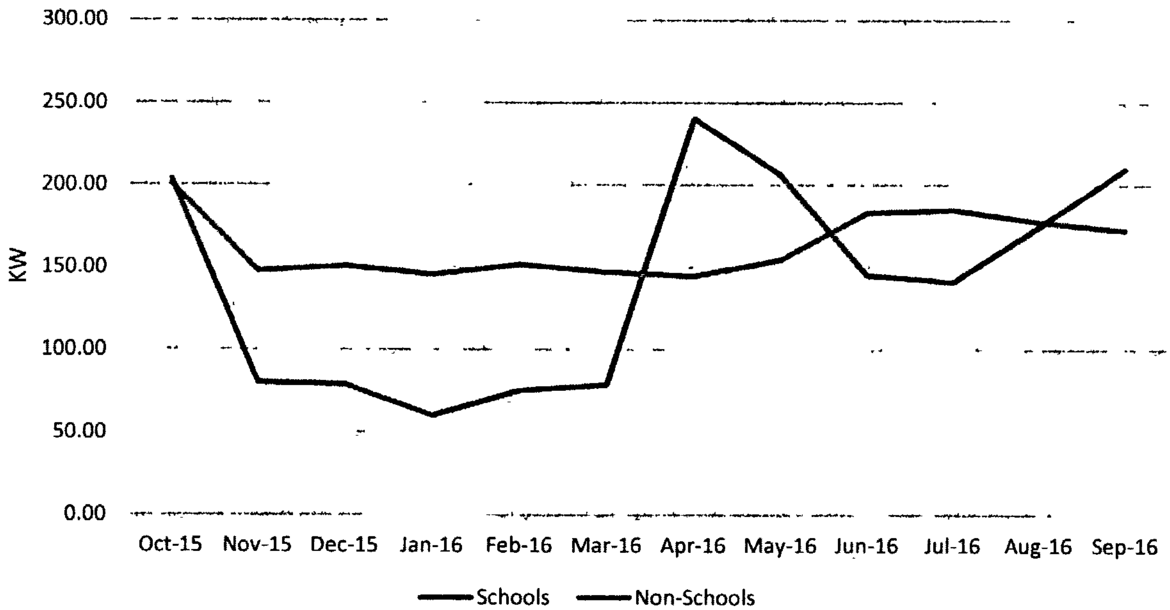


Figure E-3: Schools and Non-Schools Monthly MDD

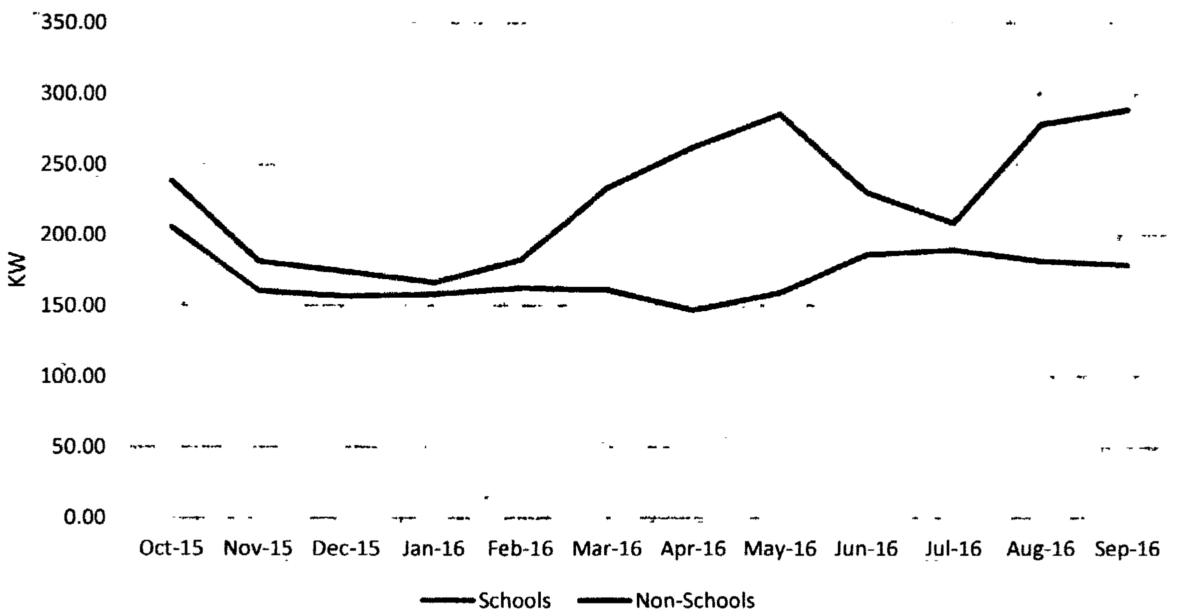
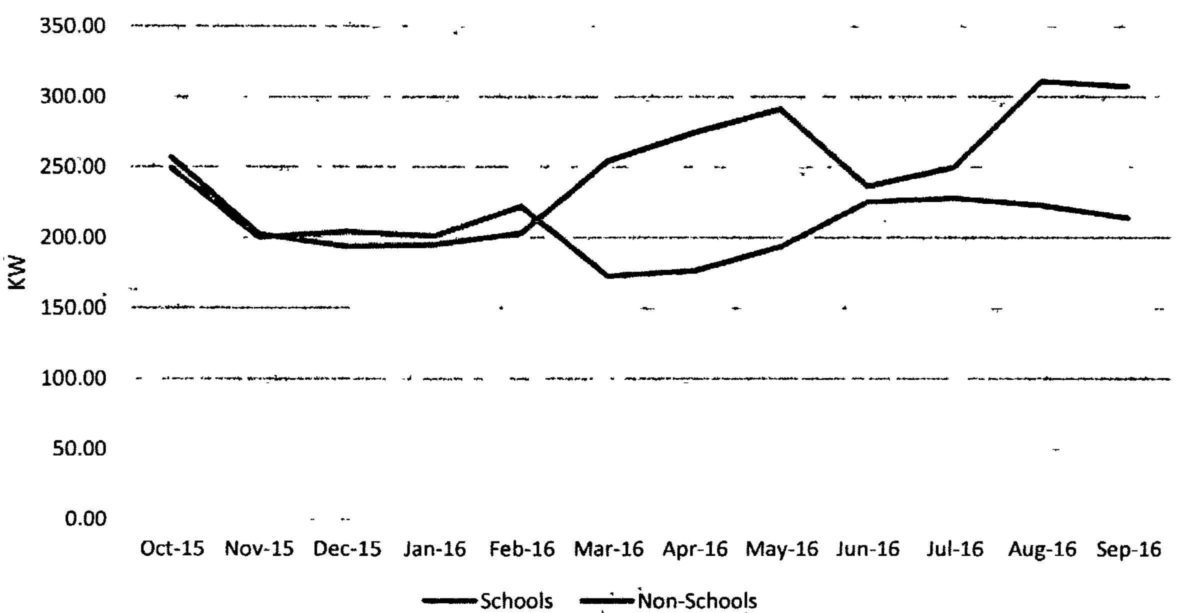


Figure E-4: Schools and Non-Schools Monthly NCD



DOCKET NO. 46831

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

RENE F. GONZALEZ

FOR

EL PASO ELECTRIC COMPANY

FEBRUARY 2017

EXECUTIVE SUMMARY

Mr. Rene F. Gonzalez is a Senior Rate Analyst with the Rates and Regulatory Affairs group in El Paso Electric Company's ("EPE" or "Company") Regulatory Affairs Department. In his testimony, Mr. Gonzalez describes the cost of service model EPE employs to produce the Texas jurisdictional cost of service study that supports EPE's revenue requirement and rate design proposals, the solar jurisdictional allocation, and the development of baseline revenue requirements to support future Distribution Cost Recovery Factor ("DCRF") and Transmission Cost Recovery Factor ("TCRF") applications.

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SUBJECT PAGE

EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Rene F. Gonzalez. My business address is 100 N. Stanton Street, El Paso, Texas, 79901.

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as a Senior Rate Analyst in the Rate Research section of the Rates and Regulatory Affairs group.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. In 2005, I graduated from the University of Texas at El Paso with a Bachelor of Business Administration with a double major in Economics and Finance. After graduation, I joined ADP (Automatic Data Processing) as an Account Executive in the Insurance Services Division as a licensed Property and Casualty insurance agent specializing in the sale of Workers Compensation Insurance, and later transferred and worked as a Retention Specialist for the same division. In 2010, I obtained a position with the City of El Paso as a Procurement Analyst in the Purchasing Department.

I was employed by EPE in October 2012 in the Rate Research section of the Rates and Regulatory Affairs group as an Associate Rate Analyst. In November of 2014, I earned a progressive promotion to Staff Financial Analyst. In 2016, I received a graduate certificate from New Mexico State University in Public Utility Regulation & Economics, and in October, I earned a progressive promotion to Senior Rate Analyst. Additionally, I have attended professional development seminars covering rate design, marginal cost, and the Electronic Quarterly Report of the Federal Energy Regulatory Commission ("FERC").

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES WITH EPE.

A. As a senior analyst in the Rates and Regulatory Affairs section, my responsibility is to perform or assist in the preparation of economic, customer, statistical, cost, and rate design studies and analysis; to develop models and methodologies for cost of service, profitability, and pricing studies; for conducting annualization, jurisdictional, and class cost of service studies; and for the development of and the filing of the FERC Electric Quarterly Report.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes, I have previously filed testimony with the Public Utility Commission of Texas ("PUCT" or "Commission") for Energy Efficiency Cost Recovery Factor ("EECRF") cases, Docket Nos. 44677 and 45885.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents and describes the jurisdictional cost of service study ("JCOS") used by EPE. I discuss the jurisdictional allocators, the appropriateness of the 4 Coincident Peak – Average & Excess ("4CP-A&E") allocator, solar jurisdictional allocation, direct assignment of costs, and the derivation of baselines to support future Distribution Cost Recovery Factor ("DCRF") and Transmission Cost Recovery Factor ("TCRF") applications, and EPE's requested Texas Revenue Requirement.

Q. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits, which are attached to this testimony:

- Exhibit RFG-1: Jurisdictional Energy and Demand Allocator Adjustment For Solar,
- Exhibit RFG-2: Monthly System Peak Demands,
- Exhibit RFG-3: Jurisdictional Cost of Service Study Summary,
- Exhibit RFG-4: Distribution Baseline Revenue Requirement, and
- Exhibit RFG-5: Transmission Baseline Revenue Requirement.

Q. WHAT SCHEDULES DO YOU SPONSOR?

A. I sponsor the following schedules:

- A-1 Cost of Service – Texas Retail,
- B-1.1 Texas Retail, and
- P-12 Support for Production Allocation Methodology.

Q. WERE THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

III. JURISDICTIONAL ALLOCATION STUDY AND MODEL OVERVIEW

Q. IS A JURISDICTIONAL COST OF SERVICE STUDY REQUIRED AS PART OF A GENERAL RATE CASE FILING?

A. Yes. The PUCT's Electric Utility Rate Filing Package for Generating Utilities ("RFP") requires utilities with non-Texas jurisdictional sales to file a schedule summarizing the utility's overall cost of service on a Texas retail basis through use of a jurisdictional allocation study in support of Schedules A and B.

Q. WHAT DATA ARE USED IN EPE'S JURISDICTIONAL ALLOCATION STUDY?

A. The data is based on EPE's Test Year ended September 30, 2016. The historical Test Year data was compiled from EPE's accounting records, which are maintained in accordance with the FERC Uniform System of Accounts as prescribed by the Commission.

As discussed in the testimony of EPE witness Jennifer I. Borden, the historical Test Year was adjusted for known and measurable changes to obtain adjusted total Company amounts.

Q. WHAT ARE THE STEPS INVOLVED IN DEVELOPING A JURISDICTIONAL COST OF SERVICE STUDY?

A. The JCOS study consists of three steps: functionalization, classification, and allocation (or direct assignment).

Q. PLEASE DESCRIBE COST FUNCTIONALIZATION.

A. After all the individual cost components representing the total Company revenue requirement have been collected for the cost of service study, the components are separated according to the function or physical service they provide. These functions are:

- Production – costs associated with the production of energy and capacity, including purchased power,
- Transmission – costs associated with the high voltage transmission system that transports power to load centers,
- Distribution – costs associated with distributing the energy from the transmission system to the end users,

- Customer Service – costs associated with providing service to the customer–e.g., service drops, metering, billing, etc., and
- Administrative and General – common costs, such as management, buildings, software, support services, etc., which are incurred to support the other functions of electric service.

Q. PLEASE DESCRIBE COST CLASSIFICATION.

A. The second step is to classify the functionalized costs according to the characteristics of the utility service being provided. The three principal cost classifications are demand-related costs, energy-related costs, and customer-related costs.

Demand-related costs are those costs that are related to the kilowatt ("kW") demand that the customers place on the system at any point in time. These costs vary with the maximum demand imposed on the various components (facilities) of the power system by the customers. Energy-related costs are those costs that are related to the kilowatt-hours ("kWh") of energy that the customer utilizes over time. These costs, such as fuel, vary with the overall quantity of energy supplied. Customer-related costs are those costs incurred as a result of the number of customers on the system. These costs, such as metering and billing, are incurred to serve individual customers.

Q. ONCE EPE'S COSTS OF SERVICE ARE FUNCTIONALIZED AND CLASSIFIED, HOW ARE COSTS ASSIGNED?

A. After functionalization and classification, jurisdictional responsibility for each cost is then determined through direct or indirect allocations. Operating and accounting data are used to develop allocation factors by jurisdiction that correspond to each cost causation factor (demand, energy, and customer). These allocation factors are then calculated as percentages (i.e., Texas retail as a percent of total Company). The allocation factors are then applied to specific costs and rate base items to derive EPE's cost of service for Texas, with remaining costs allocated to other jurisdictions. This allocation is then summarized by the cost of service model and forms the basis for allocating items that are not specifically functionalized. If costs were incurred to benefit a clearly identifiable jurisdiction, a direct assignment of that component is made, e.g., distribution substations that are located in a specific jurisdiction are assigned to that jurisdiction.

Q. WHAT ARE DIRECTLY ASSIGNABLE COSTS?

A. Directly assignable costs include regulatory assets, items affected by the actions of specific regulatory bodies, and costs incurred only by a specific jurisdiction and/or class. For example, meter reading expense is a distribution activity that is jurisdiction specific and as such is directly assigned to the jurisdiction that "caused" this activity. Within the cost of service regulatory model, the Texas amount of directly assignable costs are directly assigned to the "Texas" column, with New Mexico and FERC amounts are shown in the "Other" column.

Q. PLEASE DESCRIBE HOW THE COST OF SERVICE STUDIES ARE PRESENTED IN THE FILING.

A. Workpapers A-1 and B-1.1 present the results of EPE's JCOS study for the total Company and Texas Retail, as adjusted and as requested. The P Schedules present the assignment of cost of service to the Texas rate classes.

Q. HAS EPE MADE ANY CHANGES TO THE COST OF SERVICE MODEL SINCE DOCKET NO. 44941?

A. Yes, EPE has implemented the use of a new software application called PowerPlan Regulatory Management Suite ("RMS") that integrates with EPE's existing general ledger platform. The RMS is a proprietary server-based application that produces a working version in Microsoft Excel format of both the jurisdictional and class cost of service models that can be shared with the parties in the case

Q. HAS THE METHODOLOGY OF THE JURISDICTIONAL MODEL CHANGED WITH THE USE OF RMS?

A. No, the methodology has not changed. The RMS provides a more efficient and detailed means of developing the JCOS. Note, however this JCOS contains cost allocation modifications agreed to by EPE in its last base rate case, Docket No. 44941. I discuss two of these modifications in more detail later in my testimony.

IV. JURISDICTIONAL COST OF SERVICE STUDY

Q. DESCRIBE EPE'S JURISDICTIONAL COST OF SERVICE STUDY.

A. The JCOS study is produced from an integrated analysis and data management system that captures, organizes, measures, and presents the cost of service at various levels. For the jurisdictional level, each row of the model consists of the total Company costs to provide service. The columns of the study consist of the allocation of total Company costs to the Texas jurisdiction and Other jurisdictions ("Other" includes any costs allocable to New Mexico and FERC). The development of the cost of service by jurisdiction begins with the allocation of revenues, and continues with the allocation of operating expenses, taxes, and rate base. The JCOS provides the following: a revenue requirement summary of costs to serve by jurisdiction; allocation factors employed in the study; and a revenue requirements section that provides the total cost to serve the Texas retail jurisdiction.

Q. WHAT TYPES OF ALLOCATORS ARE USED IN THE JURISDICTIONAL COST OF SERVICE STUDY?

A. The RMS utilizes two general types of allocators: imported or "external" allocators, and dynamic or "internal" allocators. External allocators are provided to the Rates Department by the Economic Research Department and include energy, demand, and customer allocators. For example, demand-related costs are allocated according to the jurisdictional contribution to total system coincident peak demand and are allocated using a demand allocator.

In contrast, a dynamic allocator is derived from a combination of allocators or other allocation results developed from accounts that have already been allocated; examples include Gross Plant and Labor. Gross Plant is gross property, plant, and equipment. In this example, the various functions of electric plant accounts for plant in service are each initially allocated to each jurisdiction using allocators as prescribed by the National Association of Regulatory Utility Commissioners ("NARUC") in the "Electric Utility Cost Allocation Manual" ("NARUC Manual"). Then, as mentioned above, these results are used internally to develop a Gross Plant allocator (GROSSPLT). The Gross Plant allocator is then used to allocate other costs such as property taxes.

Q. HOW ARE THE JURISDICTIONAL ENERGY, DEMAND, AND CUSTOMER ALLOCATION FACTORS DEVELOPED?

A. For Energy and Demand allocators, adjusted energy data is provided by the Rates Department to EPE witness George Novela and the Economic Research

Department. The Economic Research Department then develops energy and demand allocators with the adjusted energy data, as discussed in the testimony of EPE witness Manuel Carrasco. Similarly, the Rates Department provides the annualized number of customers to produce customer allocators.

Q. WERE ANY ADJUSTMENTS MADE FOR SOLAR FACILITIES?

A. Yes. Adjustments were made to reflect purchased power contracts specific to certain solar facilities in Texas and New Mexico.

Q. HOW ARE COSTS FOR PURCHASED POWER FROM THE APPLICABLE SOLAR FACILITIES RECOVERED FROM CUSTOMERS?

A. Energy from four purchased power contracts in New Mexico that were entered into in order to meet renewable portfolio standard requirements are recovered directly from New Mexico customers through the New Mexico Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC"). In Texas, EPE recovers the costs of energy from the Newman solar purchased power contract directly from Texas customers through the fixed fuel factor. As discussed in the testimony of EPE witness David C. Hawkins, the Company has imputed capacity to the Newman solar purchased power contract and is directly assigning this imputed capacity to the Texas jurisdiction. As I discuss below, the capacity benefits from these solar contracts are directly assigned to each jurisdiction.

Q. DOES THE ENERGY ALLOCATOR NEED TO TAKE LOSSES INTO ACCOUNT?

A. Yes. Customers are served at different voltage levels and, therefore, have different losses associated with service. For proper allocation of costs, the energy allocator takes losses into account. EPE's latest loss study is included with Schedule O-6.3

and describes the development of the energy allocator including the adjustment for losses to appropriately reflect sales "at the source". Broadly, EPE combines all retail sales, calculates line losses included with sales at the meter, and then develops the total energy requirement produced at the source needed to deliver electricity to EPE's customers. This topic is also covered within the testimony of EPE witness Novela.

The demand and energy loss factors used in jurisdictional allocation are the voltage differentiated energy loss factors proposed in EPE's most recent fuel reconciliation filing, Docket No. 46308. The loss study is included in Schedule O-6.3. See Schedule P-9 for assignment of loss factors to Texas, New Mexico, and FERC, sponsored by EPE witness Novela.

Q. WHAT OTHER ADJUSTMENTS WERE MADE TO THE JURISDICTIONAL ENERGY ALLOCATOR?

A. Energy from EPE's solar resources that were built to serve a specific jurisdiction's customers was directly assigned to the relevant jurisdiction and removed from the retail customers' energy usage used in the jurisdictional energy allocator, as discussed above. This calculation is shown in Exhibit RFG-1.

Q. WHY IS THIS AN APPROPRIATE ADJUSTMENT TO THE JURISDICTIONAL ENERGY ALLOCATOR IN THE TOTAL COMPANY COST OF SERVICE STUDY?

A. The adjustment is appropriate because the costs associated with these solar resources are recovered from customers in specific jurisdictions and are directly assigned to the relevant jurisdiction in the JCOS.

Q. HAS THIS METHODOLOGY BEEN PRESENTED IN OTHER FILINGS?